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BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Corporation Commission
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COMMISSIONERS
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BOYD DUNN

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	**DOCKET NO. E-01345A-16-0036**
IN THE MATTER OF FUEL AND PURCHASED POWER PROCUREMENT AUDITS FOR ARIZONA PUBLIC SERVICE COMPANY.	**DOCKET NO. E-01345A-16-0123** **STAFF'S NOTICE OF FILING DIRECT TESTIMONY**

The Utilities Division ("Staff") of the Arizona Corporation Commission ("Commission") hereby files the Redacted Direct Testimony of Ralph C. Smith and the Direct Testimony of Matt Connolly relating to Rate Design in the above-captioned Dockets.

The Highly Confidential information contained in Ralph C. Smith's Testimony will be provided under seal to the Commissioners, their Policy Advisors, the assigned Administrative Law Judge, and to Arizona Public Service Company ("Company"). Staff will also provide the Highly Confidential information contained in Ralph C. Smith's Testimony to those parties who have executed a Protective Agreement in this case.

RESPECTFULLY SUBMITTED this 3rd day of February 2017.

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On this 3rd day of February, 2017, the foregoing document was filed with Docket Control as an Utilities Division Pre-Filed Testimony, and copies of the foregoing were mailed on behalf of the Utilities Division to the following who have not consented to email service. On this date or as soon as possible thereafter, the Commission's eDocket program will automatically email a link to the foregoing to the following who have consented to email service.

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BEFORE THE ARIZONA CORPORATION COMMISSION

TOM FORESE
Chairman
DOUG LITTLE
Commissioner
BOB BURNS
Commissioner
ANDY TOBIN
Commissioner
BOYD DUNN
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01345A-16-0036
IN THE MATTER OF FUEL AND PURCHASED POWER PROCUREMENT AUDITS FOR ARIZONA PUBLIC SERVICE COMPANY	DOCKET NO. E-01345A-16-0123

DIRECT RATE DESIGN

TESTIMONY

OF

MATT CONNOLLY

EXECUTIVE CONSULTANT II

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 3, 2017

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EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NOS. E-01345A-16-0036 AND E-01345A-16-0123

Staff's testimony contains analysis and recommendations regarding Arizona Public Service Company's ("APS") request for the elimination or waiver of certain compliance requirements.

Staff recommends the following:

- The following Retail Electric Competition Rules be suspended until further order of the Commission:
    - Annual Electric Competition Filing (R14-2-1613 (A)
    - Annual Consumer Information Label (R14-2-1617 (A), (C), (D) and (G))

- APS be granted a waiver of the annual report listing all existing Net Metering Facilities, the inverter power rating or generator rating, the monthly amount of energy delivered and the peak demand for each net metering facility as required by R14-2-2308 but should continue to collect and maintain this information in anticipation of providing it upon possible Staff request.

- APS be relieved of the requirement included in Decision No. 68112, dated September 9, 2005, ordering it to continue to participate in benchmarking studies that compare its practices to other utilities in the industry and to provide that benchmarking analysis to the Commission and Staff.

- APS be relieved of the requirement included in Decision No. 68645, dated April 12, 2006, ordering it to annually file with Docket Control reports that detail the load shape of the participants served under experimental rates ET-2 and ECT-2.

- APS be relieved of the requirement included in Decision No. 69569, dated May 21, 2007, ordering it to update the three Schedule 8 (bill estimation schedule) allocation data sets it uses for estimating kWh and kW for 1) Summer and Winter on-peak energy usage percentages by customer classifications, 2) Load Factor percentages by customer classifications and 3) Energy Usage kWh per day by customer classifications.

- APS be relieved of the requirement that it file the report described in the Ordering Paragraph found in Decision No. 70531, dated September 30, 2008, that it include in its annual Renewable Energy Standard and Tariff ("REST") implementation plan filing information describing, pursuant to the terms of the Solana Purchase Power Agreement, the amount of any damage payment collected, the cause for the collection and how the amount was calculated on page 22, lines 1-6.

- APS be relieved of the requirement included in Decision No. 71244, dated August 6, 2009, ordering it to annually submit a report detailing the transmission plant or other costs underlying the Transmission Cost Adjustor ("TCA") reset.

- APS be relieved of the requirement included in Decision No. 71275, dated September 17, 2009, ordering it to annually report the actual metered production of performance meters installed at schools that received an up-front incentive to purchase a renewable energy system and not report any phantom Renewable Energy Credits in connection with those systems.

- APS be relieved of the requirement included in Decision No. 71448, dated December 30, 2009, ordering it to establish a carbon tracking mechanism designed to track and set aside all carbon credits generated from its non-carbon emitting generation fleet, including renewable energy and energy efficiency projects identified in the Settlement Agreement.

- APS be relieved of the requirement included in Decision No. 71448, dated December 30, 2009, ordering it to, prior to the implementation of any off shoring of jobs, file notice of its plans with the Commission.

- APS be relieved of the requirement included in Decision No. 71958, dated November 1, 2010, ordering it to notify the Commission as part of all future Renewable Energy Standard ("RES") Implementation Plans, whether the inclusion of the Freeport-McMoRan Bagdad, Inc. project in APS's commercial Distributed Energy ("DE") program has precluded any other non-residential renewable DE system from receiving utility incentives.

- APS be relieved of the requirement included in Decision No. 72022, dated December 10, 2010, ordering it to file a one to two page RES summary that will accompany the filings required in Arizona Administrative Code ("A.A.C.") R14-2-1812 (Compliance Filings) and R14-2-1813 (Implementation Plans) and a PowerPoint presentation of the REST filing.

- APS be relieved of the requirement included in Decision No. 72022, dated December 10, 2010, ordering it to include, as part of future annual REST plan filings, whether its affiliates, its employees or its directors have any financial or other interest in renewable energy projects.

- APS be relieved of the requirement that it file the report described in the Ordering Paragraph found in Decision No. 72058, dated January 6, 2011, that it include in its annual Renewable Energy Standard and Tariff ("REST") implementation plan filing information describing, pursuant to the terms of the Perrin Ranch Purchase Power Agreement, the amount of any damage payment collected, the cause for the collection and how the amount was calculated on page 10, lines 25-28.

- APS be relieved of the requirement included in Decision No. 72582, dated September 15, 2011, ordering it to file annual reports, beginning in May 2012, detailing the development of the Electric Vehicle ("EV") market with APS's service territory.

- APS be relieved of the requirement included in Decision No. 73089, dated April 4, 2012, ordering it to present an overview of its Annual DSM Progress Report to the Commission at a spring (April or May) DSM Open Meeting to be scheduled within 60 days of APS filing its Annual DSM Progress Report on March 1 of each year.

- APS be relieved of the requirement included in Decision No. 73089, dated April 4, 2012, ordering it to report the level of spending associated with non-energy efficiency measures in the Appliance Recycling program as part of the included information in its Annual DSM Progress Reports.

- APS be relieved of the requirement included in Decision No. 73089 ordering it to report detailed information on how savings from the Bid for Efficiency pilot measure are verified as part of the included information in its Annual DSM Progress Reports.

- APS not be relieved of the requirement included in Decision No. 68112 ordering it to conduct an audit of APS's kW and kWh estimation, meter reading, and billing practices, have the results certified by APS' Director of Regulatory Compliance and provide those results to the Commission and Staff every three years.

- APS not be relieved of the requirement included in Decision No. 71310, dated October 30, 2009, ordering it to, in order to ensure that the key findings from the Nuclear Performance Reporting Standard ("NPRS") for Palo Verde are highlighted each year, annually present those key findings to the Commissioners at the Commission's annual Summer Preparedness meeting.

- APS not be relieved of the requirement included in Decision No. 71310 ordering it to annually report the capacity factor ("CF") and associated information for its Palo Verde units.

- APS not be relieved of the requirement included in Decision No. 73089 ordering it to include in its Annual DSM Progress Reports whether, and what type of, DSM measures are installed by customers subsequent to the receipt of study or design assistance incentives.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Matt Connolly. I am an Executive Consultant II employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as an Executive Consultant II.

A. I provide information, analysis and support to Staff on utility-related filings, applications and a variety of other utility-related matters.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Arts Degree in History from Westminster College in Fulton, Missouri.

Since joining the Commission in June of 2014, I have participated in numerous cases and regulatory proceedings involving electric, gas, water, and telecommunication utilities. I have testified on matters involving telecommunications applications for Certificates of Convenience and Necessity and a Rulemaking. Additionally, I have attended utility-related seminars sponsored by the National Association of Regulatory Utility Commissioners ("NARUC") and the National Regulatory Research Institute ("NRRI") on a variety of utility regulation matters. I previously provided testimony regarding a request for elimination of compliance requirements in Docket No. E-01933A-15-0322.[1]

[1] See, Notice of Filing Staff's Direct Testimony Regarding Rate Design and Cost of Service, June 24, 2016, *In the matter of the application of Tucson Electric Power Company for the establishment of just and reasonable rates and charges designed to realize a reasonable rate of return on the fair value of the properties of Tucson Electric Power Company devoted to its operations throughout the state of Arizona and for related approvals.*

Q. As part of your employment responsibilities, were you assigned to review matters contained in Docket No. E-01345A-16-0036?

A. Yes.

Q. What is the scope of your testimony in this case?

A. I am presenting Staff's analysis and recommendations in response to Arizona Public Service Company's ("APS") request for the waiver or elimination of a number of compliance items.

COMPANY REQUESTED COMPLIANCE ITEMS TO BE ELIMINATED

Q. APS has requested to be relieved of compliance with certain Retail Electric Competition Rules. Specifically, APS requests to be relieved of filing the report on electric competitive services per the Annual Electric Competition Filing required by R14-2-1613(A) and the Annual Consumer Information Label as required by R14-2-1617. Does Staff believe APS should be granted this request?

A. Yes. Staff notes that the Consumer Information Label is specifically addressed in R14-2-1617 (A), (C), (D) and (G). APS based its request on the fact that there is no electric competition in Arizona at this time, and thus the reason for the required filings no longer exists, and the information provided in the required reports can already be found in other required reports such as the utility annual report and the annual IRP filing. Staff agrees with APS and recommends that the requirement for the filings discussed above be suspended for APS until further order of the Commission.

Q. APS has requested to be relieved of the requirement that it file an annual report listing all existing Net Metering Facilities, the inverter power rating or generator rating, the monthly amount of energy delivered and the peak demand for each net metering facility as required by R14-2-2308. Does Staff believe APS should be granted this request?

A. Yes, with a caveat. APS states that as of December 31, 2015, it has had over 40,500 net metering connections, including both residential and non-residential. APS believes the information provided in this report is redundant, and the annual compliance reports it currently provides under the Renewable Energy Standard and Tariff Rules provide similarly substantial information. Staff believes APS should be granted a waiver of the R14-2-2308 requirement to file the annual report but should continue to collect and maintain this information in anticipation of providing it upon possible Staff request.

Q. APS has requested to be relieved of the requirement included in Decision No. 70531, dated September 30, 2008, that it include in its annual Renewable Energy Standard and Tariff ("REST") implementation plan filing information describing, pursuant to the terms of the Solana Purchase Power Agreement, the amount of any damage payment collected, the cause for the collection and how the amount was calculated. APS states this is a redundant requirement as Decision No. 72022, dated December 10, 2010, orders APS to report any damages or other considerations received as a result of REST PPA contract non-compliance. Does Staff believe APS should be granted this request?

A. The language of Decision No. 72022 orders APS to include, as part of future annual REST plan filings, a list of any cases within the previous three calendar years where APS has received damages or other considerations as a result of non-compliance related to REST contracts. Staff agrees with APS that this is a redundant requirement when compared with the ordering language from Decision No. 70531 and believes APS should be relieved of this requirement.

Q. APS has requested to be relieved of the requirement included in Decision No. 72058, dated December 16, 2011, that it include in its annual REST implementation plan filing information describing, pursuant to the terms of the Perrin Ranch Purchase Power Agreement, the amount of any damage payment collected, the cause for the collection and how the amount was calculated. APS states this is a redundant requirement as Decision No. 72022, dated December 10, 2010, orders APS to report any damages or other considerations received as a result of REST PPA contract non-compliance. Does Staff believe APS should be granted this request?

A. The language of Decision No. 72022 orders APS to include, as part of future annual REST plan filings, a list of any cases within the previous three calendar years where APS has received damages or other considerations as a result of non-compliance related to REST contracts. Staff agrees with APS that this is a redundant requirement when compared with the ordering language from Decision No. 72058, and believes APS should be relieved of this requirement.

Q. APS has requested to be relieved of the requirement included in Decision No. 71275, dated September 17, 2009, ordering it to annually report the actual metered production of performance meters installed at schools that received an up-front incentive ("UFI") to purchase a renewable energy system and not report any phantom Renewable Energy Credits in connection with those systems. APS states these systems were all installed in 2010 in accordance with the program where residential incentive funds were transferred to school projects and that this requirement is now redundant as APS is required to report only actual production after the first year for all projects. Does Staff believe APS should be granted this request?

A. Yes. In response to a Staff informal data request, APS clarified that the redundant reporting refers to Paragraph 32 in Decision No.72737 (January 18, 2012), where the Commission required APS to report actual annual production of grid-tied photovoltaic systems after the year in which the system was installed. APS goes on to state that it was required to report actual annual production for the grid-tied photovoltaic systems installed as a result of the 2009 School UFI program because, at the time, APS did not meter all systems and today, photovoltaic systems have production meters installed, and actual annual production is reported for all metered systems for compliance purposes. Staff agrees with APS's reasoning, that the reporting requirement in Decision No. 71275 is therefore now redundant and recommends that this compliance relief request be granted.

Q. APS has requested to be relieved of the requirement included in Decision No. 71244, dated August 6, 2009, ordering it to annually submit a report detailing the transmission plant or other costs underlying the Transmission Cost Adjustor ("TCA") reset. The report is broken down by the projects and the Operation and Maintenance related to those projects along with any other information that would help the Commission and ratepayers determine how and where the TCA funds are spent. The

report also includes the projects and operation and maintenance expense that APS believes will be included in the following year's TCA reset. APS states that this report was made redundant by the reporting requirements contained in Decision Nos. 73262 and 73183. Does Staff believe APS should be granted this request?

A. Yes. Decision No. 71244 requires APS to prepare a report each year detailing the transmission plant or other costs underlying the TCA reset request, and docket the report with APS's application for a TCA reset. Decision No. 73183, dated May 24, 2012, includes a Settlement Agreement, labeled Exhibit A. Section XIII, Transmission Cost Adjustment Mechanism, 13.3 of Exhibit A requires APS to file a notice with Docket Control that includes its revised TCA tariff, along with a copy of its FERC information filing of its annual update of transmission service rates pursuant to its Open Access Transmission tariff ("OATT"). This notice is to be filed with the Commission by May 15 of each year. Additionally, Page 7, Lines 1-3 in Decision No. 73262, dated July 30, 2012, requires APS to include in its annual filing to update its Adjustment Schedule TCA-1 a summary sheet containing the numerical inputs to the new TCA-1 rates as listed in Finding of Fact No. 5. Finding of Fact No. 5 states that these numerical inputs should include the information contained in the tables in Decision No. 73262 as well as the revenue requirement and billing determinant information for the four customer groups found in TCA-1. The tables in Decision No. 73262 include the transmission costs embedded in base rates, the current and proposed TCA rates and the difference in the two TCA rates. In response to an informal Staff Data Request, APS states that the supporting data required by these decisions include the same data required by the reporting requirement in Decision No. 71244 and therefore believes that the initial compliance requirement (in Decision No. 71244) is now redundant. Staff agrees with APS that this is a redundant requirement when compared with the ordering language from Decision No. 71244 and believes APS should be relieved of this requirement.

Q. APS has requested to be relieved of the requirement included in Decision No. 71310, dated October 30, 2009, ordering it to, in order to ensure that the key findings from the Nuclear Performance Reporting Standard ("NPRS") for Palo Verde are highlighted each year, annually present those key findings to the Commissioners at the Commission's annual Summer Preparedness meeting. APS states that this requirement is redundant as APS's Summer Preparedness presentations provide an overview of all APS's generating plants. Does Staff believe APS should be granted this request?

A. No. In APS's most recent summer 2016 Energy Preparedness Special Open Meeting Presentation ("Presentation"), a single page dedicated to Palo Verde includes information regarding fuel sourcing and an overall station capacity factor for 2015. APS filed its most recent NPRS in Docket E-01345A-09-0506 on January 27, 2016. This NPRS includes detailed information such as the capacity factor calculations for each generating unit, capacity unit forecasts, discussion of any known and/or anticipated extraordinary events or equipment problems that could reduce the capacity factor and discussion of any regulatory issues that could reduce capacity factors. The only other discussion in the Presentation regarding generating plants is a single page discussing coal supply to the Four Corners and Cholla Power Plants. Given that APS is actually only reporting on one key NPRS finding, the overall station capacity factor, and the reason the Presentation provides an overview of all APS's generating plants is because it includes mention of Palo Verde, Staff believes this compliance request should be denied.

Q. APS has requested to be relieved of the requirement included in Decision No. 68112, dated September 9, 2005, ordering it to continue to participate in benchmarking studies that compare its practices to other utilities in the industry and to provide that benchmarking analysis to the Commission and Staff. APS states that this

requirement is no longer necessary as APS representatives participate in industry associations and working groups that regularly share information on these issues and benchmarking studies do not provide any additional information. Does Staff believe APS should be granted this request?

A. Yes. In response to a Staff informal data request, APS stated it last filed a Benchmarking Study in this matter on May 28, 2008. APS also stated it participates in various industry associations and working groups that include the Edison Electric Institute (EEI) and Chartwell, a utility industry information provider, which provides platforms for collaboration on a variety of specific issues including customer billing and that it regularly participates in benchmarking studies and other information sharing forums with both of these associations. Staff is of the opinion that since the Commission has not held APS to the requirement that it continue to provide a benchmarking analysis, this requirement is no longer active. Additionally, as Staff is recommending that APS continue to provide an audit of APS's kW and kWh estimation, meter reading, and billing practices (see below), a benchmarking analysis is unnecessary.

Q. APS has requested to be relieved of the requirement included in Decision No. 68112, dated September 9, 2005, ordering it to conduct an audit of APS's kW and kWh estimation, meter reading, and billing practices, have the results certified by APS's Director of Regulatory Compliance and provide those results to the Commission and Staff every three years. APS states that the audits are no longer necessary as three (3) consecutive audits have shown APS's practices are robust and function as intended and the audits have found no significant issues needing review or additional discussion. Does Staff believe APS should be granted this request?

A. No. Staff is of the opinion that this requirement should remain in place to ensure APS's estimation, meter reading billing practices do not degrade as a result of the implementation of APS's new billing system.

Q. APS has requested to be relieved of the requirement included in Decision No. 68645, dated April 12, 2006, ordering it to annually file with Docket Control reports that detail the load shape of the participants served under experimental rates ET-2 and ECT-2. APS states that specific reporting is no longer necessary as the ET-2 and ECT-2 rates are now permanent and addressed in general rate cases. Does Staff believe APS should be granted this request?

A. Yes. Staff has the option and ability to request load shapes from APS at any time it determines it requires this information.

Q. APS has requested to be relieved of the requirement included in Decision No. 69569, dated May 21, 2007, ordering it to update the three Schedule 8 (bill estimation schedule) allocation data sets it uses for estimating kWh and kW for 1) Summer and Winter on-peak energy usage percentages by customer classifications, 2) Load Factor percentages by customer classifications and 3) Energy Usage kWh per day by

customer classifications. Updates were ordered to occur through general rate case or tariff filings, whichever comes first, within three months of any changes in these data that are greater than 5 percent as determined by APS's annual Load Research data. APS states that this requirement is no longer necessary as the allocation data have only changed once by more than 5 percent since the bill estimation procedures were developed and there is no reason to expect they will change significantly in the future. Does Staff believe APS should be granted this request?

A. Yes. On December 3, 2015, APS filed an application in Docket No. E-01345A-15-0386 to revise its Service Schedule 8 – Bill Estimation in order to conform with the standard methodology used in its new customer information and billing system software. This application was subsequently approved per Decision No. 75752, dated September 19, 2016. In response to Staff's question concerning the impact of Decision No. 75752 on this compliance relief request, APS indicated it believes that with the implementation of its new customer information system APS will no longer use allocation data in the estimation process and that Decision No. 75752 makes this requirement irrelevant as a revised Schedule 8 for Bill Estimation has been approved and will take effect in March of 2017. Staff agrees with APS and believes the requirement included in Decision No. 69569 should be eliminated.

Q. APS has requested to be relieved of the requirement included in Decision No. 71310, dated October 30, 2009, ordering it to annually report the capacity factor ("CF") and associated information for its Palo Verde units. APS states that reporting on CF is no longer necessary as the capacity factor at Palo Verde has improved steadily since the standard was developed. Does Staff believe APS should be granted this request?

A. No. The requirement ordered in Decision No. 71310 was, according to the Findings of Fact in this Order, put in place so that the Commission would be able to have the necessary information in order to determine if underperformance problems at the Palo Verde Nuclear

Power Plant may be attributed to imprudence or poor management decisions. It was determined that the Nuclear Performance Reporting Standard would provide such information. In response to an informal Staff data request, APS stated that the Commission and ACC Staff have many opportunities to monitor Palo Verde's performance, most notably the daily status report produced by Palo Verde that is provided each day to ACC Staff engineers, and that APS also provides status reports to the Commission and Staff in the Commission's Summer Preparedness Open Meeting, the Resource Planning dockets, in rate cases, and through regularly scheduled individual conversations with Commissioners and other Commission personnel. APS goes on to state that it seeks to eliminate only the annual report currently required by the NPRS, as this specific information is provided in many other forums as detailed above. As indicated earlier, APS filed its most recent NPRS in Docket E-01345A-09-0506 on January 27, 2016, and this NPRS includes detailed information such as the capacity factor calculations for each generating unit, capacity unit forecasts, discussion of any known and/or anticipated extraordinary events or equipment problems that could reduce the capacity factor and discussion of any regulatory issues that could reduce capacity factors. It is Staff's view that while, in the view of APS, all of the aforementioned Palo Verde performance information may appear to eliminate the need for the NPRS, the performance information is being provided for specific purposes or to meet the requirements of specific events such as a rate case. Additionally, as Palo Verde could be regarded as the flagship of APS's operations as well as carrying the inherent safety concerns of a working nuclear power plant, Staff does not believe over reporting can be an issue with Palo Verde. Staff recommends this request be denied.

Q. APS has requested to be relieved of the requirement included in Decision No. 71448, dated December 30, 2009, ordering it to, prior to the implementation of any off-shoring of jobs, file notice of its plans with the Commission. The notice is to include

an analysis demonstrating the need for the off-shoring as well as the other cost cutting measures APS undertook to reduce expenses prior to filing its off-shoring plan with the Commission. APS states that the compliance requirement was put into place at a time when some Arizona utilities were reporting to be considering off-shoring certain technical operations and was intended to be a preventive measure. Does Staff believe APS should be granted this request?

A. Yes. In response to a Staff informal data request, APS stated that it does not, has not, and does not intend to replace full-time employees with any off-shored positions and therefore, this reporting requirement is unnecessary. Staff has no evidence to believe otherwise and recommends this compliance request be granted.

Q. APS has requested to be relieved of the requirement included in Decision No. 71448, dated December 30, 2009, ordering it to establish a carbon tracking mechanism designed to track and set aside all carbon credits generated from its non-carbon emitting generation fleet, including renewable energy and energy efficiency projects identified in the Settlement Agreement. A report on the tracking mechanism, and any potential for trading of the credits contained within it, is to be filed annually with the Commission. APS states that this requirement is no longer necessary as it was set in time when it appeared likely that a federal carbon pricing or cap-and-trade policy would be enacted but with the implementation of the Clean Power Plan (Plan), no additional policies are expected. Does Staff believe APS should be granted this request?

A. Yes. In response to a Staff informal data request, APS indicated that it only participates in the purchase and surrender of carbon credits when making opportunity wholesale energy sales into California and that APS must purchase carbon credits to support day-ahead or Energy Imbalance Market opportunity wholesale energy sales into California, and then surrender those carbon credits to the California Air Resources Board (CARB) at the time of the transaction. APS reiterated that given the current status of the Plan, and the probable upcoming changes to the Plan, it is unlikely that any national market will develop in the future. Staff agrees with APS and believes the requirement included in Decision No. 71448, should be eliminated.

Q. APS has requested to be relieved of the requirement included in Decision No. 71958, dated November 1, 2010, ordering it to notify the Commission as part of all future REST Implementation Plans, whether the inclusion of the Freeport-McMoRan Bagdad, Inc. project in APS's commercial Distributed Energy ("DE") program has precluded any other non-residential renewable DE system from receiving utility incentives because APS is already in compliance with its non-residential renewable DE requirements as a result of having signed the Solar Agreement with Freeport-McMoRan Bagdad, Inc. If APS finds that commercial DE projects will be or were precluded, APS will also be required to request from the Commission, in future REST Implementation Plans, additional funding for the commercial systems that would otherwise be precluded. APS states that this requirement is no longer necessary as the Commission has eliminated incentives for commercial distributed generation systems; therefore, the project can no longer preclude the receipt of incentives. Does Staff believe APS should be granted this request?

A. Yes. Staff agrees with the reasoning APS provides.

Q. APS has requested to be relieved of the requirement included in Decision No. 72022, dated December 10, 2010, ordering it to file a one to two page REST summary that will accompany the filings required in Arizona Administrative Code ("A.A.C.") R14-2-1812 (Compliance Filings) and R14-2-1813 (Implementation Plans) and a PowerPoint

presentation of the REST filing. APS states that when this requirement was instituted, APS's REST filings were large and complicated and current Plans only request a continuation of existing programs (no new programs), are only six (6) to seven (7) pages in length overall and contain executive summaries. Does Staff believe APS should be granted this request?

A. Yes. In response to Staff's informal data request, APS stated that the elimination of the summaries will not eliminate any information, as all information contained in the summaries is also contained in the filing itself. Staff agrees with the reasoning APS provides.

Q. APS has requested to be relieved of the requirement included in Decision No. 72022, dated December 10, 2010, ordering it to include, as part of future annual REST plan filings, whether its affiliates, its employees or its directors have any financial or other interest in renewable energy projects. APS states that the status of the renewable energy markets have evolved since this requirement was instituted. Since APS owns distributed generation currently, and new incentives are not available, there is no longer any conflict of interest concern. Does Staff believe APS should be granted this request?

A. Yes. Staff agrees with the reasoning APS provides. Staff has the option and ability to request this information from APS at any time.

Q. APS has requested to be relieved of the requirement included in Decision No. 72582, dated September 15, 2011, ordering it to file annual reports, beginning in May 2012, detailing the development of the Electric Vehicle ("EV") market within APS's service territory. APS states that its application in Docket No. R-01345A-10-0123[2] was intended to compliment the Department of Energy's EV Project, which APS claims

[2] *In the Matter of Arizona Public Service Company's Application for Approval of Proposed Electric Vehicle Readiness Demonstration Project.*

has since run its course. APS also states that the EV market today advances mainly through private endeavor and thus this report is no longer necessary. Does Staff believe APS should be granted this request?

A. Yes. Staff agrees with the reasoning APS provides.

Q. APS has requested to be relieved of the requirement included in Decision No. 73089, dated April 4, 2012, ordering it to present an overview of its Annual Demand Side Management ("DSM") Progress Report to the Commission at a Spring (April or May) DSM Open Meeting to be scheduled within 60 days of APS filing its Annual DSM Progress Report on March 1 of each year. APS states that since this requirement was instituted, the Commission has declined to change the EE rules and the Company now uses Staff's cost-benefit methodology thus this presentation is no longer necessary. Does Staff believe APS should be granted this request?

A. Yes. Staff agrees with the reasoning APS provides.

Q. APS has requested to be relieved of the requirement included in Decision No. 73089, dated April 3, 2012, ordering it to include in its Annual DSM Progress Reports whether, and what type of, DSM measures are installed by customers subsequent to the receipt of study or design assistance incentives. APS states that this requirement was intended to ensure that study/design expenses were justified by the customer actually installing recommended measures and that reports continue to support the conclusion that study expenses lead to customer projects therefore making this reporting no longer necessary. Does Staff believe APS should be granted this request?

A. No. Staff believes evaluation of DSM programs and measures are a continuing and ongoing process and elimination of this reporting is premature.

Q. APS has requested to be relieved of the requirement included in Decision No. 73089, dated April 4, 2012, ordering it to report the level of spending associated with non-energy efficiency measures in the Appliance Recycling program as part of the included information in its Annual DSM Progress Reports. APS states that the Appliance Recycling program has been terminated. Does Staff believe APS should be granted this request?

A. Yes. Staff believes that APS can be relieved of this requirement until such time that the Appliance Recycling Program is resurrected.

Q. APS has requested to be relieved of the requirement included in Decision No. 73089, dated April 4, 2012, ordering it to report detailed information on how savings from the Bid for Efficiency pilot measure are verified as part of the included information in its Annual DSM Progress Reports. APS states that the Bid for Efficiency pilot program was never implemented and therefore this requirement is not necessary. Does Staff believe APS should be granted this request?

A. Yes. In response to a Staff informal data request, APS revealed that in the latter part of 2012, when evaluating information from potential contractor responses to an APS Request For Information, APS found that even the least costly bids would be significantly more expensive than simply incorporating the concepts of the program into already existing DSM custom measures. APS also stated that in addition, the cost effectiveness evaluations on the program as proposed by the contractors showed a Societal Cost Test ratio of less than 1. And therefore, APS did not pursue the Bid for Efficiency program as a standalone measure, but rather treated these applications as custom measures in the existing Solutions for Business program. Staff believes APS's explanation to be reasonable and recommends that this compliance relief request be granted.

SUMMARY OF RECOMMENDATIONS

Q. What are Staff's Recommendations in the testimony presented here?

A. Regarding APS's proposed request for the waiver or elimination of certain compliance items, Staff recommends the following:

- The following Retail Electric Competition Rules be suspended until further order of the Commission:
  - Annual Electric Competition Filing (R14-2-1613 (A))
  - Annual Consumer Information Label (R14-2-1617 (A), (C), (D) and (G))

- APS be granted a waiver of the annual report listing all existing Net Metering Facilities, the inverter power rating or generator rating, the monthly amount of energy delivered and the peak demand for each net metering facility as required by R14-2-2308 but should continue to collect and maintain this information in anticipation of providing it upon possible Staff request.

- APS be relieved of the requirement included in Decision No. 68112, dated September 9, 2005, ordering it to continue to participate in benchmarking studies that compare its practices to other utilities in the industry and to provide that benchmarking analysis to the Commission and Staff.

- APS be relieved of the requirement included in Decision No. 68645, dated April 12, 2006, ordering it to annually file with Docket Control reports that detail the load shape of the participants served under experimental rates ET-2 and ECT-2.

- APS be relieved of the requirement included in Decision No. 69569, dated May 21, 2007, ordering it to update the three Schedule 8 (bill estimation schedule) allocation data sets it uses for estimating kWh and kW for 1) Summer and Winter on-peak energy usage percentages by customer classifications, 2) Load Factor percentages by customer classifications and 3) Energy Usage kWh per day by customer classifications.

- APS be relieved of the requirement that it file the report described in the Ordering Paragraph found in Decision No. 70531 that it include in its annual Renewable Energy Standard and Tariff ("REST") implementation plan filing information describing, pursuant to the terms of the Solana Purchase Power Agreement, the amount of any damage payment collected, the cause for the collection and how the amount was calculated on page 22, lines 1-6.

- APS be relieved of the requirement included in Decision No. 71275, dated September 17, 2009, ordering it to annually report the actual metered production of performance meters installed at schools that received an up-front incentive to purchase a renewable energy system and not report any phantom Renewable Energy Credits in connection with those systems.

- APS be relieved of the requirement included in Decision No. 71448, dated December 30, 2009, ordering it to establish a carbon tracking mechanism designed to track and set aside all carbon credits generated from its non-carbon emitting generation fleet, including renewable energy and energy efficiency projects identified in the Settlement Agreement.

- APS be relieved of the requirement included in Decision No. 71448, dated December 30, 2009, ordering it to, prior to the implementation of any off-shoring of jobs, file notice of its plans with the Commission.

- APS be relieved of the requirement included in Decision No. 71958, dated November 1, 2010, ordering it to notify the Commission as part of all future REST, whether the inclusion of the Freeport-McMoRan Bagdad, Inc. project in APS's commercial Distributed Energy ("DE") program has precluded any other non-residential renewable DE system from receiving utility incentives.

- APS be relieved of the requirement included in Decision No. 72022, dated December 10, 2010, ordering it to file a one to two page RETS summary that will accompany the filings required in Arizona Administrative Code ("A.A.C.") R14-2-1812 (Compliance Filings) and R14-2-1813 (Implementation Plans) and a PowerPoint presentation of the REST filing.

- APS be relieved of the requirement included in Decision No. 72022, dated December 10, 2010, ordering it to include, as part of future annual REST plan filings, whether its affiliates, its employees or its directors have any financial or other interest in renewable energy projects.

- APS be relieved of the requirement that it file the report described in the Ordering Paragraph found in Decision No. 72058 that it include in its annual Renewable Energy Standard and Tariff ("REST") implementation plan filing information describing, pursuant to the terms of the Perrin Ranch Purchase Power Agreement, the amount of any damage payment collected, the cause for the collection and how the amount was calculated on page 10, lines 25-28.

- APS be relieved of the requirement included in Decision No. 72582, dated September 15, 2011, ordering it to file annual reports, beginning in May 2012, detailing the development of the Electric Vehicle ("EV") market within APS's service territory.

- APS be relieved of the requirement included in Decision No. 73089, dated April 4, 2012, ordering it to present an overview of its Annual DSM Progress Report to the Commission at a spring (April or May) DSM Open Meeting to be scheduled within 60 days of APS filing its Annual DSM Progress Report on March 1 of each year.

- APS be relieved of the requirement included in Decision No. 73089, dated April 4, 2012, ordering it to report the level of spending associated with non-energy efficiency measures in the Appliance Recycling program as part of the included information in its Annual DSM Progress Reports.

- APS be relieved of the requirement included in Decision No. 73089, dated April 4, 2012, ordering it to report detailed information on how savings from the Bid for Efficiency pilot measure are verified as part of the included information in its Annual DSM Progress Reports.

- APS not be relieved of the requirement included in Decision No. 68112, dated September 9, 2005, ordering it to conduct an audit of APS's kW and kWh estimation, meter reading, and billing practices, have the results certified by APS' Director of Regulatory Compliance and provide those results to the Commission and Staff every three years.

- APS not be relieved of the requirement included in Decision No. 71310, dated October 30, 2009, ordering it to, in order to ensure that the key findings from the Nuclear Performance Reporting Standard ("NPRS") for Palo Verde are highlighted each year, annually present those key findings to the Commissioners at the Commission's annual Summer Preparedness meeting.

- APS not be relieved of the requirement included in Decision No. 71310, dated October 30, 2009, ordering it to annually report the capacity factor ("CF") and associated information for its Palo Verde units.

- APS not be relieved of the requirement included in Decision No. 73089, dated April 3, 2012, ordering it to include in its Annual DSM Progress Reports whether, and what type of, DSM measures are installed by customers subsequent to the receipt of study or design assistance incentives.

Q. Does this conclude Staff's direct rate design testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

TOM FORESE
Chairman
BOB BURNS
Commissioner
DOUG LITTLE
Commissioner
ANDY TOBIN
Commissioner
BOYD DUNN
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01345A-16-0036
IN THE MATTER OF FUEL AND PURCHASED POWER PROCUREMENT AUDITS FOR ARIZONA PUBLIC SERVICE COMPANY	DOCKET NO. E-01345A-16-0123

DIRECT RATE DESIGN

TESTIMONY

OF

RALPH C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 3, 2017

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DIRECT RATE DESIGN TESTIMONY OF
STAFF WITNESS RALPH C. SMITH

Mr. Smith's direct testimony on rate design on behalf of the Arizona Corporation Commission Utilities Division Staff ("Staff") reviews Arizona Public Service Company's ("APS" or "Company") proposals for cost of service, revenue allocation, and rate design. Mr. Smith also addresses the rates proposed by APS for Service Schedule 1 and for Service Schedule 9, the APS-proposed Economic Development rate discount program. His rate design testimony also addresses the APS-proposed modifications to various rate surcharge mechanisms, including the Lost Fixed Cost Recovery mechanism ("LFCR"), the Environmental Improvement Surcharge ("EIS"), and the Transmission Cost Adjustment ("TCA"). Finally, Mr. Smith's testimony also addresses the current AG-1 program of APS and other rate design issues referred to this docket relating to AMI Meters.

Mr. Smith's testimony begins by discussing Staff's Rate Design Plan. Mr. Smith discusses the fact that utilities that have installed AMI often develop meter data management systems that allow for the extraction of energy and demand data for billing purposes. This is becoming more important because residential customers are increasingly becoming non-homogenous with differences in how they obtain energy (distributed generation and other forms) and different lifestyles, demographics, and work patterns. Staff's rate plan has been informed by recent rate cases of other utilities including UNS Electric, Inc. and Tucson Electric Power Company. It has also been informed by the Commission's Investigation of the Value and Cost of Distributed Generation. Rate design options should recognize the concepts of individual customer characteristics, energy, demand, Time of Use ("TOU") and seasonality characteristics. All customers should have a choice of rate plans and should receive education on those various rate plans so that they can make an informed choice about which rate plan works best for them. Customer education is critical because of significant customer confusion regarding demand rates and other new rate design concepts that are now possible because of advanced metering.

APS's current residential rate offerings include a standard two-part rate (E-12) (which has about 480,000 customers). APS has also been very successful with residential customer voluntary participation in TOU rates and demand-based rates. APS currently has approximately 450,000 residential customers participating in its TOU rates (ET-1 which is frozen and uses a 9am to 9pm peak and ET-2, which is open to new customers and has a noon to 7pm peak). APS also has approximately 120,000 residential customers participating in three-part rates that include a demand charge. APS's current three-part residential rates include ECT-1R, which is frozen and uses a 9am to 9pm peak and ECT-2, which is open to new customers and has a noon to 7pm peak. Three-part residential rates are not new to APS. APS has offered a three-part demand rate to residential customers for more than 35 years and is currently serving approximately 120,000 customers on the rate.

Staff recommends that APS should conduct an informational and educational campaign, including providing all residential and small general service customers having AMI meters with their monthly On-Peak and Off-Peak demands. Staff recommends that the Company offer customers access to their usage information through a website or other means of access. The Company should also develop an education program to help customers understand their usage information and how customers can manage their usage and change the size of their bills by voluntarily selecting an alternative to a traditional two-part electric service tariff.

Staff's Rate Design Plan includes the continuation of Two Part Rates which include the Basic Service Charge and an Energy Rate. The Energy Rate may be based upon TOU. Staff's Plan also includes Three Part Rates which consists of a Basic Service Charge, an Energy Rate and a Demand Rate. Again the Energy Rate under the Three Part Rate incorporates TOU. Time of Use Rates incorporate the concept of off peak and on peak pricing which gives the customer the ability to lower his energy bills by using more energy during off peak periods. A Demand Charge reflects the customer's peak usage during a particular period of time when the demand on the system is at its highest. All of Staff's rate design proposals are optional and left to customer choice. APS currently has a successful Three Part Rate offering. Staff recommends that APS continue to offer Three Part Rates but on a voluntary basis as it has done in the past. Staff also presents General Service Rates, based on adjusting APS's existing rates (other than rates being eliminated) to produce the Staff adjusted cost of service.

Staff recommends that the Company's residential rates be consolidated into updated rate structures consisting of a Two-Part rate for very small residential customers (similar to the APS proposed Rate R-XS, but with the threshold to be determined), a standard Two-Part Rate (similar to existing rate E-12 but with a higher customer Basic Service Charge and the rate components updated to reflect the cost of service), a Two-Part Time of Use rate (similar to existing rate ET-2 with a customer Basic Service Charge lower than the updated rate E-12, and the rate components updated to reflect the cost of service, and two Three-Part rates similar to the APS-proposed R-2 and R-3. The specific details of these residential rates structures have not been developed, and would need to be tested for customer impacts prior to being approved and implemented. Staff supports updating the on-peak and off-peak usage hours for the existing TOU and Three-Part Rates.

Staff believes there is a disconnect in the way the Basic Service Charge is calculated in the existing rate structures. Subject to analysis of customers bill impacts and the concept of gradualism, Staff recommends that an optimal rate structure would have a higher Basic Service Charge for the standard Two-Part Rate; a Basic Service Charge for the TOU rate that is lower than the Basic Service Charge for the standard Two-Part Rate, and a Basic Service Charge for the Three-Part Rate that is lower than the Basic Service Charge for the TOU rate. By way of illustrating this concept, if the Basic Service Charge for standard Two-Part service (similar to existing rate E-12 were set at $16), the corresponding Basic Service Charge for the TOU rate (similar to ET-2) would be lower (say $14 per month) and the Basic Service Charge for the Three-Part Rates would be a further step lower (say $12 per month). Staff recommends testing this concept for customer bill impacts and applying the concept of gradualism prior to implementation. The Basic Service Charge is one of the rate components that drives customer behavior. In comparison, currently the Basic Service Charge for the standard residential Two-Part Rate is $0.285 per day, which equates to $8.67 per month, and the Basic Service Charge for rate ET-2 (the TOU rate- is $$0.556, which equates to $16.91 per month. K Under the current structure of Basic Service Charges between alternative rates such as these, customers are incented to utilize a standard Two-Part rate over the alternative time varying rate. Staff believes, this is an issue that needs to be addressed and is recommending that over time, Basic Service Charges be higher in Two-Part Rates then in the alternative TOU and Three-Part Rates.

Under Staff Rate Design Plan, the Company's existing residential rates would be updated to reflect changes related to the cost of service and the new rates would updated effective as provided in the Commission's Order. The Company should initiate an education campaign to ensure that customers understand how their updated rate design tariff works and how the customer can save energy and money under the particular rate design the customer has chosen.

APS's proposed Rate Design includes new residential rates, Rates R-1, R-2 and R-3, which include mandatory demand charges for all residential customers except those with low usage, which APS defines as below 600 kWh per month (Rate R-XS). Staff continues to support the concept of updated three-part residential rates with Demand Charges for residential customers, but only on a voluntary basis. Staff recommends that three-part residential rates be voluntary for all APS residential customers. Staff supports residential customer choice to select three-part rates pursuant to customer educational programs to be conducted by APS. Staff opposes APS's proposal to involuntarily transition all but very small residential customers onto Three-Part Rates. Staff recommends that the use by residential customers of Three-Part Rates be at the customer's choice, and not imposed upon the customer involuntarily by APS. A Two-Part residential rate should continue to be available for all APS residential customers.

APS has proposed imposing a mandatory demand charge component on rates E-32 (extra small general service) and E-32TOU XS. Staff recommends that the small general service customers continue to have the option to choose a traditional two-part rate, or to voluntarily select a new three-part rate that includes a demand charge. Similar to residential customers, Staff continues to support the concept of updated three-part small general service rates with demand charges, but only on a voluntary basis. Staff recommends that three-part small general service rates be voluntary for all APS residential customers. To facilitate this, Staff is presenting rates E-32 XS and E-32TOU XS adjusted to reflect Staff's CCoSS, at the traditional two-part rates, as well as at alternative three-part rates, that customers would have the option of voluntarily selecting.

Mr. Smith also evaluates APS's Class Cost of Service Study ("CCoSS") and places its results into perspective. Staff recommends that it be used as a guide to revenue allocation and a source of unit cost data for rate design. He presents the CCoSS results using the base rate revenue deficiency recommended in Staff's Direct Testimony. Mr. Smith provides the Staff recommendation for the allocation of Staff's recommended rate increase among the major rate classes. This recommendation is tempered by the concept of gradualism.

Based on a review of APS' Application, responses to Staff data requests and consistent with Staff's long-term Rate Design Plan, Mr. Smith provides recommendations for the rate design for each of APS' rate classes. The impact of Staff's proposed rate design is provided for residential and small general service customers. For residential and small commercial customers, Staff recommends that customers continue to have a choice between rates, and the rate options available to such customers continue to include a traditional Two-Part rate without Demand Charges.

Staff has included a presentation of rates using APS's existing rate structure for residential customers adjusted for Staff's revenue requirement and CCoSS results. As noted above, APS has proposed to collect its calculated residential revenue requirement via the APS-proposed new residential Rates R-XS, R-1, R-2 and R-3. As previously stated, Staff recommends that residential customers not be involuntarily transitioned onto Three-Part rates but rather that APS's residential customers be allowed to voluntarily choose to select a Three-Part Rate (R-1, R-2, or R-3), from among other options as well. To facilitate this, Staff presents information showing what the APS-proposed new residential Rates R-XS, R-1, R-2 and R-3 would be if adjusted to correspond with the Staff's adjusted revenue requirement and CCoSS results.

Staff's adjusted CCoSS results (as well as the APS CCoSS results) show that the Residential Solar Energy Rates category is not recovering the cost of service that is allocated and assigned to that group. APS's existing residential solar customers will be grandfathered. Staff recommends that the existing rate structure for the grandfathered Distributed Generation customers be frozen and not available for new, non-grandfathered customers. Staff proposes that DG customers have a choice between either a Three-Part Rate that includes a Demand Charge (i.e., that they be able to choose a Three-Part Rate that includes a Demand Charge, similar to the R-1 or R-3 rate) or a Two-Part Rate that includes a higher fixed charge relating to the cost of service. For new, non-grandfathered Distributed Generation customers, Staff recommends a reevaluation of the CCoSS results and supports the concept of a Grid-Access charge to help address cost-recovery shortfalls for customers in that group that select a two-part rate option that does not include a demand charge

The Grid Access Charge would apply to new, non-grandfathered residential solar customers who choose a Two-Part Rate, to address cost recovery related to APS's provision of electric service to such customers. Staff believes that there are currently too many moving pieces to reliably develop a Grid Access Charge at this time, but that efforts be made at later stages of the current case (such as after a base rate revenue requirement is determined and the results of the RCP model are reviewed). Staff proposes to update the CCoSS results and re-evaluate the amount of shortfall for consideration in the development of a Grid Access Charge for new, non-grandfathered residential Distributed Generation customers who choose a Two-Part Rate that does not include Demand Charges.

As a result of the Commission's Decision No. 75859 in the Value of Distributed Generation proceeding (E-00000J-14-0023) Staff is in the process of developing a Resource Comparison Proxy rate to comply with Decision No. 75859.

In recognition that the final base rate revenue requirement may be different than the recommendation made in Staff's direct testimony, Staff has also presented illustrative rates designed to collect a higher amount of base rate revenue than the amount that was recommended in Staff's Direct Testimony on revenue requirements.

Pursuant to the Settlement Agreement in APS's last base rate case that was approved in Decision No. 73183, APS offered an experimental buy-through rate for the generation portion of the bill for large and extra large commercial and industrial customers. This is referred to as the "AG-1" rate. The program was limited to 200 MW of total participation. Customer interest in the program exceeded the program size limits, so APS conducted a lottery to select participants for the experimental program. The program is fully subscribed. Initially, the program had a sunset date of June 30, 2016, but the date was extended by the Commission in its Decision No. 75322 (November 25, 2015) to coincide with the ultimate rate effective date of the Decision in this rate case. APS asserts that the AG-1 rate is not sustainable and shifts revenue responsibility to other customers. APS proposes that it not be renewed. Staff agrees that the current AG-1 rate should not be renewed as is. Staff encourages APS to continue to work with its largest customers to devise a solution that addresses concerns that have been noted about the AG-1 rate. Staff does not recommend approval of an AG-1 type rate unless it can be demonstrated that no other customers will be harmed as a result of the program.

Concerning the charges proposed by APS for Service Schedule 1, Staff is in general agreement with most of the APS-proposed charges. However, Staff disagrees with certain aspects of the APS proposed charges for customers who opt-out of having an AMI meter. Staff supports the $15 meter reading fee that APS proposes to charge, because APS has reasonably demonstrated that it would incur additional costs associated with meter reading for customers who voluntarily choose to opt-out of having an AMI meter, in comparison to customers who have an AMI meter. Staff views the $15 meter reading fee as cost-based and relates to the additional costs attributable to the customer's choice to not have an AMI meter. However, Staff does not support the APS-proposed $70 installation fee. APS has not demonstrated that its cost of installing a non-AMI meter is different from its costs of installing an AMI meter, thus charging customers who choose to opt-out of having an AMI meter an additional installation fee is discriminatory. The normal Service Establishment Charge should apply. APS has also indicated that: "APS is withdrawing its initial proposal to charge a one-time set-up fee for a customer without an existing AMI meter requesting to opt-out of APS's standard metering."[1]

Concerning the APS proposal for a discounted Economic Development rate under Service Schedule 9, Staff supports this APS proposal, subject to APS including the following information in the compliance filings: When APS files the customer agreements under Service Schedule 9, APS should include a copy of its Customer Characteristics Report as well as information estimating the impact on peak demand from the new load, as well as information clearly demonstrating that (1) the discount does not exceed 25% and (2) the discounted rate is no less than APS's marginal cost of providing service. Staff also recommends strengthening the APS-proposed "Conflict of Interest" provisions to include persons who have been Pinnacle West or subsidiary officers and directors within the three-year period prior to the effective date of the Customer's Service Schedule 9 agreement.

APS is proposing modifications to its existing LFCR, including the following:

1) The Company is proposing that the LFCR rate filed on January 15th become effective on the first billing cycle in March each year unless the Commission takes specific action on the LFCR compliance filing.

2) The Company is proposing to increase the year over year cap to 2%.

3) APS is proposing to update the costs eligible for recovery. Specifically, APS is proposing that the LFCR be modified such that 100% of transmission, distribution and generation costs collected through energy charges are included and 50% of transmission, distribution and generation costs collected through demand charges are included.

4) APS is proposing to remove the LFCR opt-out rate option, which APS indicates has proven unnecessary.

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[1] See, e.g., APS response to Woodward 2.30.

5) APS is proposing that the adjustment no longer be applied to customers' bills as an equal percentage surcharge, but rather as a capacity (demand) charge per kW for customers with a demand rate and as a kWh charge for customers with a two-part rate without demand.

Staff agrees with portions of the APS-proposed LFCR modifications and does not agree with other parts. Staff does not agree with APS's first three proposed changes to the LFCR and recommends that those revisions be rejected. Concerning the LFCR opt-out option, Staff agrees with APS that this option is not widely subscribed and supports APS's proposal to discontinue the LFCR opt-out as something that customers could elect, commencing with the effective date of new rates in the current APS rate case; however, Staff recommends that customers who have already elected the LFCR opt-out (or who elect this before the effective date for new rates) be allowed to continue under that option. Staff agrees with APS's proposal to that the adjustment will be no longer be applied to customers' bills as an equal percentage surcharge, but rather as a capacity (demand) charge per kW for customers with a demand rate and as a kWh charge for customers with a two-part rate without demand.

Concerning the filing dates and review time available for the LFCR, Staff would prefer to have actual calendar information available when APS makes its annual LFCR filing. Also, Staff has determined that more time is needed for Staff to review the information and have the Commission approve the new LFCR rates. Staff recommends that new LFCR rates continue to be subject to Commission approval, prior to taking effect. Staff recommends a filing date of February 15 for APS's LFCR compliance filings and that the new LFCR rates take effect, after Commission approval, with the first billing cycle of May each year.

APS proposes certain modifications for the EIS, which include:

1) Changing the structural cap on cost recovery from a rate to a dollar amount ($0.00016 per kWh to $10M year-over-year).

2) Providing for the ability to carry over into subsequent periods any excess EIS adjustment over the annual cap. APS indicates that this addition is consistent with APS's other adjustment mechanisms, including a nominal interest component.

3) Inclusion of a balancing account to account for any differences between the allowable EIS adjustment and actual revenues received by the Company through the EIS during the recovery period.

Staff disagrees with the first two APS proposed revisions. Staff agrees with the APS proposal for an EIS balancing account. Staff recommends that the structural cap on cost recovery be maintained as a rate and that it apply on a cumulative basis, not a year-over-year basis (as APS has requested). Staff recommends that the cumulative per-kWh cap rate for the EIS be increased from the current $0.00016 to a new rate of $0.00050. With the new higher cap rate and with the rate continuing to be applied as a cumulative structural cap, there is no need for a carry-over of amounts over an annual cap that was requested by APS.

The TCA rates should not change without a corresponding change in the Formula rate mechanism. Since APS's proposal for a revenue balancing account would address only revenues and not costs, APS could over earn if revenues go up and costs go down. It would be difficult to justify that type of change in the Formula rate mechanism with FERC.

I. INTRODUCTION

A. Background and Qualifications

Q. Please state your name, position, and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I previously submitted direct testimony on behalf of the Commission's Utilities Division ("Staff") on December 28, 2016, addressing the revenue requirement, rate base, net operating income, and selected other issues, including APS' proposal for new depreciation rates. I also discussed APS' requested cost deferral and step increase for costs associated with installing selective catalytic reduction technology at its Four Corners Power Plant, and APS' requested cost deferral for its Ocotillo Modernization Project.

B. Purpose of Rate Design Testimony

Q. What is the purpose of your rate design testimony?

A. I address Staff's proposed Rate Design Plan concept. I address APS' proposed modifications to its rates. I address APS' proposals for a new residential rate design based on a three-part rate that includes demand charges. I discuss APS' proposed new rate schedule for commercial and industrial customers with extra-high load factors, and allowing larger customers to aggregate their loads for the purpose of meeting minimum load requirements for certain C&I rate schedules, as well as APS' proposals for an economic development schedule. I discuss APS' request to discontinue the experimental AG-1 rate that was implemented in APS' last rate case, Docket No. E-01345A-11-0224 pursuant to Commission Order 73183 dated May 24, 2012.

I address the rates proposed by APS for Service Schedule 1 which has various miscellaneous service charges, including APS-proposed charges for AMI-meter opt-outs, and for Service Schedule 9, which is the APS-proposed Economic Development rate discount program.

I address a rate stabilization mechanism and how APS is not proposing full revenue decoupling in the current rate case.

I also address the APS-proposed modifications to various rate surcharge mechanisms, including the Lost Fixed Cost Recovery mechanism ("LFCR"), the Environmental Improvement Surcharge ("EIS"), and the Transmission Cost Adjustment ("TCA").

Q. Please briefly describe the information you reviewed in preparation for your testimony.

A. The information I reviewed included APS' application and testimony, APS' responses to data requests of Staff and other parties, information provided to me by Staff, and other publicly available information.

Q. Are you the only Staff witness providing Direct Testimony on rate design in this Docket?

A. No. Mr. Matthew Connolly will be addressing the Company's request for the waiver or elimination of a number of compliance items.

Staff witness Candrea Allen filed Direct Testimony on December 28, 2016 to address the APS Service Schedules.

C. Content of Attachments to Testimony

Q. Have you attached any exhibits to be filed with your Rate Design Direct Testimony?

A. Yes, Attachments RCS-11 through RCS-20 are attached to my Rate Design Direct Testimony.

Q. What is shown in each of those attachments?

A. Attachment RCS-11 presents the Staff Adjusted Cost of Service Study Results

Attachment RCS-12 presents the Staff Revenue Allocation.

Attachment RCS-13 presents the Staff Proof of Revenues. This shows the current adjusted revenues for each APS rate (not including rates to be terminated or the new APS-proposed residential rates, R-XS, R-1, R-2, or R-3). It also shows the adjusted proposed revenues for each such rate per Staff and the percentage increase over adjusted existing base rate revenues.

Attachment RCS-14 presents Staff Illustrative Extra Small General Service Rate Design for Rates E-32 XS and E-32TOU XS (Current Two-Part Rates) Adjusted to Staff's Adjusted Revenue Requirement.

Attachment RCS-15 presents Staff Illustrative Extra Small General Service Rate Design Using the Structure of APS's Proposed E-32 XS Three-Part and E-32TOU XS Three-Part Rates Adjusted to Staff's Adjusted Revenue Requirement.

Attachment RCS-16 presents copies of selected APS non-confidential responses to discovery and other documents that are referenced in my rate design testimony.

Attachment RCS-17 presents copies of selected APS Confidential responses to discovery and other documents that are referenced in my rate design testimony.

Attachment RCS-18 presents copies of selected APS Highly Confidential responses to discovery and other documents that are referenced in my testimony.

II. STAFF'S RATE DESIGN PLAN

Q. Are significant changes occurring in the Company's capability to measure how and when customers are using energy?

A. Yes. The Company has expected to complete its installation of Advanced Metering Infrastructure ("AMI") by the end of 2016.[2]

Q. How has electric metering changed over time?

A. Initially there was no metering, and infant utilities charged either a flat rate per customer or charged by the number of light bulbs installed by a customer. This pricing methodology is still used for lighting (and other fixed load) customers because the number and wattage of bulbs can be accurately verified and enumerated. By not using meters, the costs of meters and meter reading do not need to be charged to those customers.

With the advent of energy meters at a reasonable cost, coupled with a wider range of lighting and appliances, utilities began to charge customers based upon the energy consumed. This type of rate design did not recognize different costs based upon demand (often expressed as load factor). Two customers using identical amounts of energy but with different usage patterns could have different levels of demand and require different amounts of generation, transmission, and distribution equipment (at very different costs), and therefore one customer

[2] See, Attachment CAM-6DR at page 13.

may be undercharged and the other overcharged if demand was not measured and taken into account. Alternatively, two customers who require the same equipment might use very different amounts of energy and again would result in one customer being undercharged and the other overcharged.

The introduction of demand meters, which measure peak demand usage within the billing period along with energy consumed, allowed for the introduction of rate forms such as the three-part rate (customer, demand and energy) or a variant (hours of use). The use of the demand meter and associated rates reduced the disparate impact of energy-only rates. Demand meters have generally not been used for residential customers due to the cost of the more complex meter, and the increased complexity of billing and the information that should be provided to the customer. The residential class was often seen as homogenous enough not to have wide usage disparities and therefore the cost of demand meters and their associated rate complexity was not justified.

For a number of years utilities have been able to measure the consumption of energy over very narrow time periods (hourly or even 15 minute intervals) but the challenge has been recording that data cost effectively and then providing that data to customers so that the customer could decide whether and how to respond and change their usage (energy) or usage pattern (demand). Interval data have been used for load research to provide an understanding of how different customers use energy and the data were typically recorded on magnetic tape and analyzed in bulk. While interval data were suitable for load research purposes, it was difficult to provide the data to a large number of customers at a reasonable cost.

Similarly, time-of-use meters could accumulate energy usage in a few time-differentiated periods but these data were only recorded and reported as On-Peak, Shoulder and Off-Peak and did not offer much information to the customer, such as when the energy was used on an interval basis.

AMI has benefited from the declining costs of electronic versus mechanical metering devices and the ability to analyze data on a customer-specific basis. Utilities that have installed AMI often develop meter data management systems that allow for the extraction of energy and demand data for billing purposes. Unfortunately, some AMI planning does not go far enough and some utilities cannot provide individual customers their usage information in a form that supports customers' decisions about how and when to use energy more effectively and efficiently.

Q. How did the confluence of new metering and information capabilities, changing customer characteristics lead Staff to consider a long-term rate design concept?

A. At this point in time, many utilities have the capability to record interval data as a result of the installation of AMI. Some utilities can provide that data to individual customers in a form that is somewhat easily understood, although additional customer education is necessary. Residential customers are increasingly becoming non-homogenous as they adopt various forms of heat and distributed generation and as their lifestyles, demographics, and work patterns become increasingly more diverse. Staff has raised the concept of offering a "plan" of how rate design should evolve so that the parties to this case could provide their input and the Commission could consider a plan in order to provide the Company's customers advance notice that changes are underway.

Q. How has the Staff's development of a Rate Design Plan for the Arizona regulated electric utilities been evolving in recent cases?

A. Staff's Rate Design Plan has been stated with specific principles in recent cases involving Arizona electric utilities, including UNS Electric, Inc. (see, e.g., Docket No. E-04204A-15-0142), and Tucson Electric Power Company (see, e.g., Docket Nos. E-01933A-15-0239/E-01933A-15-0322.) Staff's Rate Design Plan has also been informed by the ongoing developments in the Commission's Investigation of the Value and Cost of Distributed Generation (Docket No. E-00000J-14-0023). A recommended opinion and order ("ROO") in Docket No. E-0000J-14-0023 was issued on October 7, 2017. On January 3, 2017, the Commission issued Decision No. 75859.

Decision No. 75859 at pages 178-179 provides as follows:

> IT IS FURTHER ORDERED that electric utilities shall submit cost of service studies in rate cases, both pending cases and in future rate cases, which are based on models with spreadsheets containing links between inputs and outputs which are available to all parties. The cost of service study models used by the utilities shall be:
>
> > Transparent: all inputs, assumptions and calculations shall be clearly described and explained;
> >
> > Accessible: have electronic spreadsheets with links between inputs and outputs made available to all parties, and
> >
> > Flexible: to allow for the ability to change inputs and assumptions used in the calculation.
>
> IT IS FURTHER ORDERED that for the first utility rate case in which the value of DG methodology we adopt in this proceeding will be used, including pending cases, the new export compensation rate set in that case, as well as any changes to rate design, will apply only to DG customers who sign up for new DG interconnection after the effective date of the Decision issued in that utility rate case. Once a DG customer is subject to a DG export compensation rate determined by one of the DG valuation methodologies adopted by this Decision, there will be no further netting or banking of exported DG kWh for that customer. Unless unique circumstances warrant

> different results, our default policy for existing DG customers shall be that DG systems that interconnect to a utility's distribution system before the effective date of the Decision issued in that utility rate case will be considered to be fully grandfathered and continue to utilize currently-implemented rate design and net metering, and will be subject to currently-existing rules and regulations impacting DG for a period of twenty years from the date a DG system is interconnected.

Q. What principles are identified in Staff's Rate Design "Plan"?

A. There are a number of principles within this Plan.

Rates should be based on costs derived from class cost of service studies not only at the class level but also to illuminate the unit costs of individual customer, demand and energy rates. Marginal costs should be given some consideration but embedded costs are the focus. There should be a place for different test program concepts to determine how rate design may alter the need for capital investment and/or energy costs. When changes occur, it is important that those changes recognize the concept of gradualism so that the potential for rate shock is kept to a minimum.

Rate design options should recognize the concepts of customer, demand, and energy, and also recognize time-of-use ("TOU") and seasonality characteristics. The number of rate designs available to customers should be calibrated to balance the objectives of avoiding confusion and providing for customer choice and voluntary rate selection by residential and very small commercial customers. Involuntarily placing residential customers on mandatory three-part rates or imposing three-part rates on small commercial customers is not something that Staff can support. Customers should have a choice of rate plans, and should receive education on those various rate plans so that they can make an informed choice about which rate plan works best for them. The records in other recent rate cases are testament to the fact that there.is significant customer confusion regarding demand rates and other new rate design concepts that are now possible because of smart meters.

Generation pricing can now reflect the marketplace by considering seasonality, TOU, hourly pricing, and demand response.

Rates should be supported by customer-specific usage information collected under stringent privacy and security, but available to customers along with tools to help them see the impact and make decisions. In the long-term, customers might receive cost "warning" using a simple red/yellow/green indication in their home or business and, for example, their demand controllers could access detailed price information online.

Rate subsidies, as determined appropriate, should be clearly delineated and based upon and computed from standard rates. For example, a Lifeline customer would be billed as a standard residential customer, including all trackers and adjustment clauses, but also receive a specific discount. Should a Lifeline customer's situation change for the better, the only change would be the removal of the Lifeline discount, which would be easily recognized by that customer. Hence, Staffs long-term plan would adjust Lifeline eligible customers to standard residential rates, and apply discounts to those rates.

Q. How does a Three Part-TOU rate differ from a Two-Part rate in providing price signals about the cost of electric service?

A. The Two-Part Rate typically consists of a fixed Basic Service Charge and an Energy Rate component which will vary based upon customer usage. The Energy component allows the customer to increase or decrease his/her energy consumption to change the total bill. A

Two-Part Rate with TOU gives the customer more control over his/her bill because it allows the customer to utilize more energy during off-peak hours which should lower the bill. .

The Three Part-TOU Rate incorporates a fixed Basic Service Charge, an Energy Rate component which varies based upon the time energy is used by the customer and what is called a Demand Charge which reflects the customer's peak usage during a particular period of time. The Three Part-TOU rate prices the consumption and usage pattern differently by charging for both the Demand (intensity) and Energy consumed separately. In each case, the customers can choose the usage and pattern they desire and be charged appropriately for raising or lowering the utility's costs.

Q. What would be the long-term impact of this residential, Three Part-TOU rate design?

A. Customers would have greater information available to make their own energy decisions, and rates would more accurately reflect those decisions and lessen the consequential impact on other customers and the utility. Over time, customer and Demand Charges would gradually increase and Energy charges would become "purer" and lower for the distribution component. A customer could reduce costs by adjusting demand and/or by changing energy usage. However, the customer only benefits if he/she is provided with tools and education so they can make informed choices and know how to best take advantage of new rate forms.

Q. Do Three Part-TOU rates increase revenues for the utility?

A. No. If properly implemented the rates are neutral for the utility at the end of the Test Year. However, if customers choose to react to their present usage patterns the utility may see a decrease in revenue.

Q. Do Three Part-TOU rates increase costs for customers?

A. If a customer's usage pattern is the same as a "typical" customer then there should be no significant impact as Three Part-TOU rates are implemented. If a customer has an atypical usage pattern then costs may increase (for lower load factor customers) or decrease (for higher load factor) customers. Customers who are consuming electricity during the peak demand periods would pay more than customers who consume electricity during other hours of the day.

Q. Are these concepts new or new to the utility?

A. For medium and large customers, Three Part Rates with a Demand Charge component have been the norm and a Three Part-TOU rate is available. APS also has approximately 120,000 residential customers on three-part rates that include Demand Charges.

Q. What are the important principles for the move towards the rate design plan?

A. Rate design should not be changed in this fashion until customers have private, secure, easy, timely, and comprehensible access to their usage data, and until customers have been educated as to what their usage data means and how it affects their bill for electric service under the available rate options. As noted above, Staff favors voluntary customer rate choice for residential and small commercial customers, including options to choose among a Two-Part Rate, a TOU Rate and a Three-Part TOU Rate. Staff recommends that customers have the option of voluntarily selecting Three-Part TOU Rates but that such rates not be involuntarily imposed upon either residential or small commercial customers.

III. CLASS COST OF SERVICE STUDY

Q. What is the purpose of a fully allocated cost of service study?

A. Just as the rate case revenue requirements process studies each element of due Company's operations to determine the overall cost to operate the Company efficiency and effectively, a fully allocated cost of service study attempts to determine the individual cost to serve each customer class and subclass. A fully allocated class cost of service study is intended to assist the Commission to allocate revenue requirements among customer classes.

Q. How can a regulator use the class cost of service study?

A. Because customer classes use the utility's system on an interrelated or shared basis, regulators have historically used a fully allocated class cost of service study as a guideline to allocate revenue among classes. Regulators typically also consider economic, social, historical, and other factors that may affect customers when determining revenue allocation. Such considerations often result in rates that deviate from strict cost of service.

Q. Are there limitations to a cost of service study?

A. Yes. A class cost of service study involves judgment and decisions on the part of the practitioner in assigning costs to the various customer classes. In some situations, decisions are made to use a particular allocation factor for a particular account. In other situations, data used to develop an al location factor are not always complete and/or timely and the practitioner must deal with the resulting uncertainty. Consequently, the cost of service study acts as a guide in revenue allocation and in formulating rate design.

A. Rate Classes within the APS Class Cost of Service Study

Q. Has the Company provided a class cost of service study?

A. Yes. The Company provided its CCoSS based on the Test Year (twelve-month period ended December 31, 2015.[3] Schedule G provides the individual class returns for the Company's the following service classes (Residential, General Service, Irrigation/Water Pumping, Street Lighting, and Dusk-to-Dawn Lighting.

Q. Have you reviewed the CCoSS presented by the Company?

A. Yes. The CCoSS was provided as Schedules G-1 through G-7. I performed a review of the allocations, developed data requests, and reviewed the answers to Staff and other parties.

Q. Did the Company adjust or normalize its revenues?

A. Yes. The Company used a Test Year (twelve months ending December 31, 2015) and then adjusted it to reflect more normal or appropriate (from the Company's viewpoint) conditions.

Q. How has the CCoSS changed from the prior rate case (Docket No. E-01345A-11-0224)?

A. The prior CCoSS had included five general categories, Residential, General Service, Irrigation/Water Pumping, Street Lighting, and Dusk to Dawn Lighting. APS's current CCoSS contains the same five general categories, with some revisions to the components of each category, such as APS's proposal to separately identify the cost of service for residential distributed generation customers.

Q. Are the service classes used by APS in its CCoSS appropriate?

A. Yes.

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[3] APS Filing Schedule G.

Q. What CCoSS recommendation does Staff have for the Commission?

A. The Commission should use the Company's CCoSS as a general guideline (subject to gradualism) in its class revenue allocation decision for this case.

Q. Do you have an attachment that summarizes Staff's adjusted CCoSS results?

A. Yes. Attachment RCS-11 shows Staff's adjusted CCoSS results. This was produced by inputting the Staff revenue requirement adjustments into the APS-provided CCoSS Excel models.

Q. Did you find the APS CCoSS Excel models to be transparent?

A. The APS CCoSS model consists of three interlinked Excel files. The model was transparent in the sense that after inputting the Staff's revenue requirement adjustments and recommended cost of capital, the models produced an ACC jurisdictional revenue requirement that was close to Staff's presentation of its adjusted revenue requirement in its Direct Testimony filing, with minor differences being attributed to rounding. The APS CCoSS model also was based on models with spreadsheets containing links between inputs and outputs which was made available by APS to all parties. Exactly how the model was handling some of the allocations of cost was challenging to follow. Additionally, starting from the end results and tracing results back through the model was also challenging and not intuitive. The transparency of the APS CCoSS model has room for improvement. Even after participating in APS-provided training sessions, and receiving some additional aid via follow-up conference calls. Staff recommends that APS continue to work on making its CCoSS model more transparent and intuitive.

B. Separate Residential Rate Sub-Class for NEM Energy and NEM Demand Customers within the Residential Customer Class

Q. Has APS proposed creating a sub-class within the Residential Customer Class for Net Energy Metering customers?

A. Yes. APS witness Snook explains at page 23 of his Direct Testimony that it can be appropriate to create a new class or sub-class of customers for purposes of a COSS or setting rates if the service, load, or cost characteristics of the customer subgroup in question are sufficiently different from their current customer classification. Upon reviewing these characteristics for customers with solar, Mr. Snook determined that sufficient differences exist for creating a sub-class of residential customers for customers with Net Energy Metering ("NEM"). He explains that the load and energy characteristics of residential customers with and without rooftop solar are very different. APS has demonstrated that customers with rooftop solar have a load profile that is significantly different than residential without rooftop solar. Moreover, as Mr. Snook states on page 24 of his Direct Testimony:

> ... in the 2015 Test-Year, APS had 35,988 solar customers on an energy rate and almost 1,311 solar customers on a demand rate by year's end. The size of this residential solar customer sub-group, combined with its vastly different load characteristics, warrant evaluating them as a separate sub-class.

Q. Does Staff agree with APS's proposal to establish a residential sub-classification for NEM customers?

A. Not entirely. APS has established that the load and energy characteristics of NEM customers are significantly different than for traditional residential customers without rooftop solar. Additionally, the size of the NEM sub-class is sufficiently large as to warrant separate analysis in the COSS.

Thus the CCoSS in the current APS rate case needs to be updated to reflect the guidance provided in the Commission's recent Order in the Value of Solar Case. Commission Decision No. 75859 requires that existing NEM customers receive grandfathered treatment. See, Decision No. 75859, at pages 178-179.(also need to reference new order):

The new residential DG class would presumably only include new distributed generation residential customers who are not encompassed within the grandfathering provisions. Staff also notes that the default grandfathering policy set forth in the above-quoted Ordering Paragraphs "shall not apply to generally applicable rate design changes, such as changes to the basic service charge." Staff views this as offering some latitude in adjusting existing rates for components, such as the basic service charge, to address issues related to recovery of the cost of electric service.

Q. The Commission in the Value of Solar Docket also found that NEM customers are "partial requirements customers." What is the significance of this finding with respect to rate design, if any?

A. NEM customers self-generate a portion of their electric service requirements. This differs from full requirements customers who rely on APS for all of their electric service needs. NEM customers have a different load profile, different usage characteristics, and a different cost of service than other residential customers. Thus, creating a category in the cost of service analysis for the NEM customers is appropriate.

Q. How did APS reflect residential NEM customers in its COSS?

A. As explained by Mr. Snook in his Direct Testimony, APS started with the NEM customers' entire load at the house. APS does not supply the energy service when an NEM customer's self-generation is supplying energy, so APS credited against the full load, the customer's self-supply of energy service. This recognizes that NEM customers supply some of their own energy, and APS supplies various back-up and ancillary services that require APS to build, operate, and maintain its fixed infrastructure required to serve that NEM customer. Mr. Snook points out that, beginning with the NEM customers' entire site load and then explicitly crediting the value of the energy and capacity that they supply from their own rooftop solar systems, is the only transparent way to balance the benefits provided by rooftop solar systems on residential rooftops and the costs required to continue serving those customers with rooftop systems. As Mr. Snook states at page 26 of his Direct Testimony:

> By comparing the entire load at the home to the remaining household load served by APS, we can determine the infrastructure that APS no longer needs to provide as a result of the solar system. Although solar installation will have a certain maximum-production capability, that capability will only be realized at mid-day and only on sunny days. The load information reveals what actually occurred when the customer was consuming energy in contrast with the solar production at the same time.

He points out that APS's peak loads persist in the summer months beyond sunset, and the maximum peak load occurs closer to sunset than mid-day.

Q. To align cost recovery with cost causation, should the appropriate level of compensation for offsetting demand-driven infrastructure costs be based on how effective the NEM customer's solar system is at offsetting APS's peak loads?

A. Yes. To align cost recovery with cost causation for demand-driven infrastructure costs, the appropriate level of compensation should be based on how effective the NEM customer's solar system is at offsetting APS's peak loads, subject to the grandfathering provisions from Decision No. 75859 noted above.

Q. What does APS's COSS show for NEM customers?

A. As Mr. Snook explains, APS's COSS indicates for a solar customer on energy based rates, the appropriate level of production demand credit is 28.8%, transmission capacity credit is 45.6%, distribution primary and substations capacity credit is 12% and distribution secondary capacity credit is 16.2%.[4]

Q. Does Staff agree with those APS-proposed determinations?

A. No. APS's originally proposed production demand credit is being replaced by a new export compensation rate to be set in the utility's rate case (but this has not yet been done for APS)., as well as any changes to rate design, which Decision No. 75859 indicates will apply only to DG customers who sign up for new DG interconnection after the effective date of the Decision issued in that utility rate case. Staff's analysis of the APS COSS and updating of that to reflect the revenue requirement presented with Staff's Direct Testimony is presented in Attachment RCS-11. Referring to page 3 of Attachment RCS-11, there is a column with the heading "Residential Solar (Energy Rates)" which shows a cost of service recovery of 40.81 percent at present rates and 43.60 percent at the total cost of service, a negative rate of return at present rates and a negative index rate of return at present rates. Attachment RCS-11, page 3, also shows a column with the heading "Residential Solar (Demand Rates)" which shows a cost of service recovery of 79.85 percent at present rates and 82.16 percent at the total cost of service. The "Residential Solar (Demand Rates)" results show a positive rate of return at present rates (but only 0.90 percent) and a positive index rate of return (but only 0.17). These results suggest that the current Residential Solar, particularly under energy rates, is not recovering its cost of service and is being subsidized by other customers. However, these results have not yet been updated to reflect the guidance provided by Decision No. 75859 concerning the development of an export rate.

[4] See, Snook Direct Testimony at page 27.

Q. What does Staff recommend?

A. Staff recommends that the rate design concepts at this stage for APS's residential customers be viewed as a guideline for the development of rates in this case. Final rates should incorporate the guidance provided by Decision No. 75859.

IV. REVENUE ALLOCATION

Q. What non-cost considerations should the Commission consider during its deliberations on revenue allocation?

A. The Commission should consider the relative positions (from the CCoSS) of the classes along with the qualitative issues such as economic conditions for consumers, the business climate for commercial and industrial customers and past practices when deciding what portion of a revenue increase is allocated to each class.

Q. What principles do you generally use to allocate revenue among rate classes?

A. I have used the following principles:

- The individual rate classes should be gradually moved toward an UROR of 1.000 over one or more rate cases depending on the frequency of rate cases and the distance of the class' UROR from 1.000.
- Rate shock should be avoided if feasible. There should be an upper bound of 150 percent for any class' percentage increase in revenue compared to the overall percentage increase in revenue.
- Given the size and basis for the overall base rate revenue increase, no class should receive a base rate decrease.

Q. Are there other concepts that apply in this case?

A. APS's overall cost of service has increased in the current rate case due to a number of factors including the roll-in to base rates of various costs that have been collected via riders. The increased base rate revenue requirement for APS reflects cost increases that have generally benefitted all customers. Therefore, as noted above, it would be inappropriate to reduce rates for any customer class because that would send a confusing message about the cost of APS providing electric service.

Q. What is the Company's proposed revenue allocation for new base rates?

A. Based on Schedule H-1, the Company is proposing to allocate its requested $433.4 million increase 66.19 percent to the Residential class, 31.99 percent to the General Service class, 1.13 percent to the Irrigation/Water Pumping class, 0.49 percent to the Outdoor Lighting class, and 0.20 percent to the Dusk-to-Dawn Lighting class.

Q. What overall base rate percentage increases has APS proposed for each of those rate classes?

A. Based on APS's Schedule H-1, as summarized on Attachment RCS-12, the Company is proposing an overall base rate increase of 15.0 percent. APS proposes a 19.30 percent increase for the Residential class, a 10.32 percent increase for the General Service class, a 17.02 percent increase for the Irrigation/Water Pumping class, a 10.10 percent increase for the Outdoor Lighting class and a 10.11 percent increase for the Dusk-to-Dawn Lighting class.

Q. Have you modeled various revenue allocations based on Staff's recommended revenue requirements?

A. Yes. Attachment RCS-12 models Staff's proposed base rate revenue increase of $265.040 million (including roll-in of riders) a number of ways. For comparison purposes the increase was allocated:

- Using the adjusted CCoSS results, and

- Equal percentage increase (across the board by revenue)

Q. What is Staff's recommendation on revenue allocation?

A. Based upon the present adjusted CCoSS results, the principles discussed above, and the relative impacts between classes, Staff recommends that the eventual revenue requirements be allocated by increasing the Residential class base rates by 11.24 percent, General Service rates by 6.95 percent, Water Pumping rates by 11.20 percent, Street Lighting rates by 4.59 percent and Dusk-to-Dawn lighting class rates by 3.62 percent. This revenue allocation follows the general principles in moving each rate class closer to parity while avoiding rate shock for any class.

Q. If Staff's recommended revenue allocation is adopted what will the class returns be?

A. The results of the proposed revenue allocation are forecasted in Exhibit RCS-12. The UROR of the "low UROR" classes (Residential and Water Pumping) will increase and the UROR of the "high UROR" classes (General Service, Street Lighting, and Dusk-to Dawn Lighting) will decrease, moving classes towards parity.

V. PROOF OF REVENUE

Q. Have you prepared a Proof of Revenue schedule showing how the illustrative rates presented by Staff would produce the overall base rate revenue requirement?

A. Yes. A detailed Proof of Revenue is presented in Attachment RCS-13, consisting of two pages. Page 1 shows the Proof of Revenue by the five general rate classes. Page 2 shows the Proof of Revenue by individual rates, using the APS current rate structure, and shows the approximate percentage increase for each rate that would be needed to produce the Staff-adjusted base rate revenues for APS.

VI. RESIDENTIAL RATE DESIGN PROPOSALS

A. APS's Existing Residential Rates and Voluntary Customer Participation in TOU and Three-Part Rates

Q. Please discuss APS's existing residential rate structure and the approximate number of APS residential customers who have chosen to voluntarily subscribe to the TOU and Three-Part rate offerings.

A. APS's residential rate offerings include a standard two-part rate (E-12) (which has about 480,000 customers) as well as other choices, such as TOU and Three-Part rates. APS has also been very successful with residential customer voluntary participation in TOU rates and demand-based rates. APS currently has approximately 450,000 residential customers participating in its TOU rates (ET-1 which is frozen and uses a 9am to 9pm peak and ET-2, which is open to new customers and has a noon to 7pm peak). APS also has approximately 120,000 residential customers participating in three-part rates that include a demand charge. APS's current three-part residential rates include ECT-1R, which is frozen and uses a 9am to 9pm peak and ET-2, which is open to new customers and has a noon to 7pm peak. The high levels of customer participation in the TOU and three-part residential rates suggest that there is no compelling need to involuntarily migrate all but very small residential customers onto such rates. Rather the choice of rates should be voluntary (i.e., remain a customer choice) and a traditional two-part standard rate similar to the current E-12 should continued to be offered.

B. APS Proposal for Migration to Three-Part Residential Rates

Q. Please summarize the Company's residential rate design proposal.

A. The Company's Rate Design proposals have largely focused on the use of a three-part residential rate design (customer, demand, and energy charges) that would be mandatory for all residential customers except those with usage below 600 kWh per month. The Company suggests that these changes are to better align the Commission's policies with the Company's need for fixed cost recovery and system usage. The Company is also supporting gradualism when making rate design changes. For new distributed generation ("DG") customers, the Company is proposing monthly bill credits for any excess energy delivered to the Company's system.

Q. What was the Company's primary concern in developing its rate design proposals?

A. As I understand the Company's approach, the focus is the recovery of fixed costs. A concern is expressed by APS that residential DG customers (with their associated low kWh consumption) are not recovering the same percentage of fixed costs as other residential customer classes; and thus a portion of their fixed costs are being borne by someone else.

Q. Is this focus on fixed costs sufficient to support rate design changes?

A. Yes. If fixed costs are not properly accounted for in the rate design, intra-class subsidies will occur. The challenge is how to and how fast to make the changes. With new rate forms, some customers need education and support to achieve a meaningful transition.

Q. Does Staff support the mandatory migration of residential customers onto three-part rates that include demand charges that is being proposed by APS?

A. No. Staff recommends that residential customers have a choice of rates. Staff does not support the APS proposal to involuntarily migrate all but very low usage residential customers onto three-part rates.

Q. Is Staff convinced that 600 kWh per month should be used as the cut-off for a very small residential rate?

A. No. . Staff is continuing its review of the R-XS rate that has been proposed by APS for small residential customers. APS proposes that eligibility for this R-XS rate be limited to residential customers not having distributed generation and having usage less than 600 kWh per month. Staff believes that it could be useful and informative to consider a different higher kWh usage threshold for this type of very small residential customer rate. At this time, Staff is not convinced that 600 kWh per month should be used as the cut-off for a very small residential rate. Staff is seeking additional information from APS on alternatives such as using 750 kWh per month or another level as the basis for establishing a very small residential customer rate.

C. Current APS Residential Rate Plans

Q. What types of rates for electric service does APS currently offer to residential customers?

A. As explained by APS witness Miessner on pages 21-22 of his Direct Testimony, APS currently serves more than one million residential customers with a variety of rate schedules and options including an inclining block rate; two time-of-use (TOU) energy rates; two TOU demand rates; a super peak TOU rate; two dynamic rate options; and a TOU rate for electric vehicles. Optional Rider Rates are available for special requirements or services such as on-site renewable generation, green power, limited-income, and medical equipment discounts, and other specialized or experimental programs. A complete list of the current and proposed rate schedules and riders are provided in the SFR Index to Rate Schedules. Currently, APS residential customers can choose a rate plan among the options, including a non-time-of-use rate, a TOU energy rate, and a TOU demand rate. APS witness Miessner indicates that approximately 11.5% of APS's customers have chosen a TOU demand rate and another 43% a TOU energy rate.[5]

[5] See APS witness Miessner's Direct Testimony at page 22.

Q. Does Staff support having voluntary rate choices for APS residential customers?

A. Yes. Currently APS offers its residential customers a variety of rate options, including traditional two-part rates, as well as a TOU energy rate, and a TOU demand rate. APS's residential TOU demand rate is currently voluntary and has been selected by approximately 120,000 customers.

D. Summary of APS-Proposed Changes to Residential Rates

Q. What specific changes is APS proposing to residential rates?

A. APS is proposing extensive changes to residential rates. As summarized in APS witness Miessner's Direct Testimony at pages 24-26, APS proposes to:

1. Cancel the inclining block rate E-12.

2. Revise the current TOU energy rates as follows:

• Consolidate TOU rate schedules ET-1, ET-2, ET-Super Peak, and ET-EV for electric vehicles into one TOU rate with a small demand charge;

• Revise the on-peak hours to 3 p.m. to 8 p.m. weekdays, excluding designated holidays, for both winter and summer seasons;

• Increase the number of off-peak holidays;

• Reduce the difference in on-peak and off-peak prices from 4:1 to 2:1 in the summer months;

• Increase the basic service charge;

• Add a small demand charge;

• Reduce the average kWh charges; and,

• This rate is not available to partial requirements customers (with on-site generation).

3. Create a new TOU demand rate option with the following features:

• A lower service charge and a demand charge in between the other two TOU demand rates;

• The same on-peak hours of 3 p.m. to 8 p.m. as the other proposed rates; and

• This rate is not available to partial requirements customers.

4. Revise the current TOU demand rates as follows:

• Consolidate the TOU demand rates ECT-2 and ECT-1R into one TOU demand rate;

• Revise the on-peak hours to 3 p.m. to 8 p.m., consistent with the other proposed TOU demand rates;

• Increase the basic service charge; and

• Retain a moderate demand charge.

5. Create a new rate option for extra-small customers like apartments, manufactured homes, and other small dwellings with the following features:

• A service charge;

• A flat kWh charge for each season;

• No TOU or demand charges;

• Eligibility only for customers with average monthly usage of 600 kWh or less; and

• This rate is not available to partial requirements customers.

6. Allow qualifying grandfathered customers with renewable generation to stay on a current rate structure as follows:

• The current rate design options E-12 inclining block, ET-1 and ET-2 time-of-use energy and ECT-1R and ECT-2 time-of-use demand rates will be available through the grandfathering period.

• All of the charges (the basic service charge, kWh charges, and demand charge, if applicable) will be increased by an equal percent to reflect the targeted revenue increase for the residential class.

• Grandfathered customers will be able to stay on the current frozen net metering program or move to the modified net metering program for solar customers during the grandfathering period.

7. Simplify the discount programs for limited income customers and provide increased funding for growth in participation.

8. Continue the peak event pricing program, revised with new critical hours of 3 p.m. to 8 p.m., to be consistent with the proposed time-of-use hours; cancel peak time rebates.

9. Offer alternative metering service for customers that do not want to be served with the AMI metering and remote meter reading communication system; customers will be charged a one-time installation fee and a monthly meter reading fee.

10. Cancel the optional LFCR opt-out having a higher basic service charge.

11. Modify the net metering program for new solar customers.

12. Convert the Flagstaff solar experiment into the Solar Partners Program and discontinue Rate Rider Schedule CMPW.

E. APS-Proposed Residential Three-Part Rates with Demand Charges

Q. What new Residential Rates is APS requesting?

A. APS proposes the following for new residential rates, Rates R-1, R-2 and R-3, including mandatory demand charges for all residential customers except those with low usage, which APS defines as below 600 kWh per month and for which APS proposes Rate R-XS. APS's residential rate design proposals are summarized below[6]:

		Rate R-1	Rate R-2	Rate R-3
1. Basic Service Charge	($-day)	0.789	0.477	0.789
for typical month	($-month)	24.00	14.50	24.00
2. Demand Charge				
Summer on-peak	($-kW)	6.60	8.40	16.40
Winter on-peak	($-kW)	6.60	8.40	11.50
3. Energy Charges				
Summer on-peak	($-kWh)	0.15160	0.15160	0.09090
Summer off-peak	($-kWh)	0.08070	0.08080	0.05475
Winter on-peak	($-kWh)	0.12730	0.12730	0.06670
Winter off-peak	($-kWh)	0.08070	0.08080	0.05475

APS proposes that customers with extra small usage below 600 kWh per month will have an additional rate option, R-XS, having a basic service charge of $18 per month on average, no demand charge and a flat energy charge or $0.10234 per kWh for all hours and seasons. APS

[6] See APS witness Miessner's Direct Testimony at page 4. An identical table appears at page 27 of his Direct Testimony.

proposes that Rates R-1, R-2, and R-XS would not be available to new customers with on-site generation. APS proposes to base the demand charge on the maximum usage averaged over one hour during the 3 p.m. to 8 p.m. on-peak hours. Weekday off-peak hours, weekends and designated holidays would be exempt from any demand charges.

Q. Does APS have historical experience with residential three-part rates?

A. Yes. As APS witness Miessner states at pages 8-9 of his Direct Testimony, APS has offered a three-part demand rate to residential customers for more than 35 years and is currently serving approximately 120,000 customers on the rate. Customers on APS's existing residential demand rates have demonstrated they can respond to demand charges and manage their monthly demand on their bill.

Q. How does the three-part rate structure incent customers to save on their electric bill?

A. As explained by APS witness Miessner on page 20 of his Direct Testimony, the three-part rate structure rewards customers for reducing both their demand and energy. Because it is a time-of-use rate, it also provides savings for shifting usage to the off-peak hours. In essence, APS's three-part rate provides customers three opportunities to save on their bill. In comparison, the Company's two-part inclining block rate only provides one opportunity to save, by reducing the total monthly kWh energy usage.

Q. Why does APS claim that the traditional two-part residential rate designs are no longer appropriate?

A. At page 8 of his Direct Testimony, APS witness Miessner states that the traditional two-part rate designs are economically inefficient, ineffective in reducing a utility's total costs to serve customers, and are ultimately unfair:

- **Economically inefficient**. Two-part rate designs are inefficient because they do not provide the right price signals for when and how customers use electricity. Nor do they provide the correct incentives for customers desiring to invest in distributed technologies because such technologies will not be rewarded for, or focused on, reducing demand-related grid costs. Both of these issues will result in the inefficient use of and inadequate funding for the grid.

- **Ineffective**. For similar reasons, the two-part rates are also ineffective in reducing a utility's overall costs because they do not effectively incent customers to lower their monthly demand. As a result, the rates would likely only reduce the utility's energy-related costs, such as fuel, and not the demand-related costs, which include all of the extensive grid investment costs.

- **Unfair**. The two-part rates are ultimately unfair because they result in one group of customers paying the costs to serve another group of customers. This is a direct result of using two billing elements to recover the cost of three discreet and different utility services: basic services; demand-related grid services; and energy-related services.

Q. Does APS propose a demand limiter as a safeguard to protect customers that set a high demand in relation to their overall energy usage?

A. Yes. APS witness Miessner discusses the APS-proposed demand limiter at pages 29-30 of his Direct Testimony. Specifically, APS proposes a demand limiter based on a 15% monthly load factor calculation, which is an index of the relationship between kW demand and monthly kWh consumption. At page 30 of his Direct Testimony, Mr. Miessner provides an illustrative example of how the APS proposed demand limiter would function. The illustration uses a residential customer with a 5.5 kW demand with 1,000 kWh monthly consumption, which represents a 25% load factor.[7] APS's proposed demand limiter would limit this customer using 1,000 kWh to a 9.1 kW billed demand[8] even if the customer's metered one-hour demand during the on-peak hours of 3 p.m. to 8 p.m. was higher. In the example, if the customer's metered demand was 10 kW, the customer would be billed for the demand charge based on the maximum amount of 9.1 kW. The load factor index proposed by APS adjusts

[7] 1,000 kWh / (5.5 kW x 730 hours in a month) = 25.25%

[8] 1,000 kWh / (9.1 kW x 730 hours in a month) = 1,000 kWh / 6,552 = 15.26%

the maximum billed kW for the number of billing days in a month and for the customer's level of monthly kWh usage, so customers with higher usage would have a higher maximum billed demand limiter.

APS proposes that the demand limiter would not be applicable to partial requirements customers with on-site generation.

Q. Does Staff believe there is merit in having a safeguard on residential three-part rates that include demand charges?

A. Yes. Especially during the periods of more widespread adoption of three-part rates that include a demand component, Staff finds merit in having safeguards such as the APS-proposed demand limiter mechanism.

Q. What concerns does Staff have concerning the APS proposals for three-part residential rates with demand charges?

A. While Staff agrees with APS that there is economic merit in providing residential customers with three-part rates that include demand charges to better align rates with the cost of providing service, Staff has concerns about the customer acceptance of such rates and the mandatory nature of the residential rates that APS proposes in the current case. Staff acknowledges APS's long historical experience with residential Three-Part Rates, but notes that historically participation in APS's Three-Part TOU rates by residential customers was a choice by the participating customers, i.e., residential customer participation in those rates was voluntary. Both rate design programs have been very successful and both have been offered on a voluntary basis by APS.

Staff believes that there is some merit with Three-Part residential rates for new Partial Requirements customers (customer with on-site generation) after pre-specified dates (i.e., for non-grandfathered customers), since that will address cost-shifting concerns. Staff notes that APS continues to approximately 480,000 residential customers on its standard two-part rate (E-12) and does not recommend involuntarily migrating those customers onto three-part rates, but rather allowing customers a choice between a coordinated, well-designed package of residential rate options. Staff recommends that new DG customers also have other rate options, and the choice of which rate option within a specified selection should be the customer's.

Staff is very concerned APS's proposal to impose mandatory three-part rates on the general body of APS's residential customers in the current case. Staff recommends that APS continue to offer residential full requirements customers a traditional two-part rate option in the current case. The participation in three-part rates by customers should be at the customer's choice, and not mandatorily imposed on customers who do not want it.

Q. **Please speak to Customer Education and the importance of it with the introduction of Three Part Rates.**

A. Customer education is critical. Staff encourages APS to have a robust customer educational program and to explain to customers the benefits of selecting a Three-Part rate, but the choice as to whether to remain on a traditional Two-Part rate or to migrate to a Three-Part rate should be the customer's. Implementing residential Three-Part rates for the general body of APS's residential customers who do not have on-site generation should not be accomplished on a flash cut basis in a single APS rate case and should occur over a transition period that includes extensive customer education to inform customers about the new rate structures and encourage a voluntary customer transition onto the Three-Part rates. The gradual implementation of new residential rate structures that are better aligned with the cost of service is consistent with the Staff's Rate Design Plan, discussed previously in my testimony. However, forcing a more complicated three-part rate structuring on the general body of APS's residential customers is not being recommended by Staff. Rather, Staff recommends that customers have a choice of rates and the choice be up to the customer.

F. Customer Basic Service Charges, Demand Rates and per-kWh Charges

Q. Please discuss APS's proposals for increased fixed monthly customer charges.

A. Currently, APS residential customers pay basic service charges ranging from $0.285 to $0.556 per day ($8.67 to $16.91 per month). APS proposes the following basic service charges:

- $0.592 per day ($18 per month on average) for the extra-small rate, Rate R-XS;
- $0.789 per day ($24 per month) for Rate R-1;
- $0.477 per day ($14.52 per month) for Rate R-2; and
- $0.789 per day ($24 per month) for Rate R-3.

As discussed, the rates proposed by APS for Rates R-1, R-2 and R-3 also include the following demand charges:

- $0.736 per kW (approximately $22.39 per month on average) for Rate R-1;
- $0.443 per kW (approximately $13.48 per month on average) for Rate R-2; and
- $0.721 per kW (approximately $21.92 per month on average) for Rate R-3.

Staff is recommending that three-part rates for residential customers not be mandatory. Rather residential customers should have a choice to either voluntarily select a three-part rate, or to remain on a traditional two-part rate.

Q. Does Staff agree with the increased charges for those residential rates that have been proposed by APS?

A. Not entirely. Staff's recommended base rate revenue requirement is lower than the revenue requirement requested by APS. Staff's lower revenue requirement should provide a basis for having lower basic service charge increases than those requested by APS, which were based on APS's higher requested revenue requirement.

Q. Please discuss Staff's recommended approach to establishing basic service charges for a residential rate package, from which customers would be able to select the rate of their choice.

A. Staff believes there is a mismatch in the way the basic service charge is presented in existing rate structures. Subject to testing for customer bill impacts and the concept of gradualism, Staff recommends that an optimal rate structure would have a higher basic service charge for the standard two-part rate, a basic service charge for the TOU rate that is lower than the basic service charge for the standard two-part rate, and a basic service charge for the three-part rates that is lower than the basic service charge for the TOU rate. By way of illustrating this concept, if the basic service charge for standard two-part service (similar to existing rate E-12 were set at $16), the corresponding basic service charge for the TOU rate (similar to ET-2) would be lower (say $14 per month) and the basic service charge for the three-part rates would be a further step lower (say $12 per month). Staff recommends testing this concept for customer bill impacts and applying the concept of gradualism. The basic service charge is one of the rate components that drives customer behavior. In comparison, currently the basic service charge for the standard residential two-part rate is $0.285 per day, which equates to $8.67 per month, and the basic service charge for rate ET-2 (the TOU rate) is $0.556, which equates to $16.91 per month. Under the current structure of basic service charges between alternative rates such as these, customers are incented to utilize a standard two-part rate over the alternative time varying rate. Staff believes, this is an issue that needs to be addressed and is recommending that over time basic service charges be higher in two-part rates then in the alternative TOU and three-part rates.

Q. What package of residential rate offerings does Staff recommend be developed?

A. Staff recommends that the Company's residential rates be consolidated into updated rate structures consisting of a two-part rate for very small residential customers (similar to the APS-proposed Rate R-XS, but with the threshold to be determined) a standard two-part rate (similar to existing rate E-12 but with a higher customer service charge and the rate components updated to reflect the cost of service), a two-part time of use ("TOU") rate (similar to existing rate ET-2 with a customer service charge lower than the updated rate E-12, and the rate components updated to reflect the cost of service), and two three-part rates similar to the APS-proposed R-2 and R-3. The specific details of these residential rates structures have not been developed, and would need to be tested for customer impacts prior to being approved and implemented.

Q. Does Staff support updating the on-peak and off-peak usage hours for the TOU and three-part rates?

A. Yes. As discussed below, Staff supports updating the on-peak and off-peak usage hours for the TOU and three-part rates.

Q. How does Staff recommend that new residential rates be developed and implemented?

A. Staff recommends that the Company's existing residential service rates be updated to reflect changes related to the cost of service, and then frozen. Staff further recommends that the Company over a period of 6-8 months embark on a transition and education process to move customers from their existing rates to one of the new corresponding rate structures (e.g., extra small to R-XS, Standard to Standard, TOU to TOU and Demand to Demand). As rate design evolves over time, legacy rates are created. These legacy rates present significant challenges when designing new time varying rates. It is Staff's desire to mitigate some of the challenges associated with these legacy rates though the proposed transition and education process. Staff is also concerned about customer bill impacts and recommends that the new residential rate structure be tempered by the concept of gradualism and that the rate design and educational process provide customers with appropriate rate choices for managing their electric bills.

G. APS Proposal to Discontinue Inclining Block Rates

Q. What reasons has APS stated for its proposal to discontinue the inclining block rate?

A. APS witness Miessner's Direct Testimony at pages 32-33 states that APS's current inclining block rate (rate E-12) has four pricing blocks in the summer season ranging from \$0.097 to \$0.173 per kWh; the highest block price is about 80% higher than the first block. However, Mr. Miessner states that this price difference is not based on any difference in cost of service. It does not cost more per kWh to serve a larger user than a smaller one. In fact, the larger user has a lower unit (per kWh) cost of service. He states that the difference only has the effect of discouraging customers with larger usage from using this rate.

Q. Does Staff agree with APS's proposal to discontinue the inclining block rate, Rate E-12?

A. Yes. As explained by APS, the rate is not based on differences in the cost of service. Staff agrees with APS's proposal to discontinue Rate E-12.

H. APS Proposed Changes to On-Peak Hours

Q. What on-peak hours are currently used in APS's TOU rates?

A. As explained by APS witness Miessner on page 33 of his Direct Testimony APS currently has two TOU energy rates, ET-1 and ET-2, with on-peak hours of 9 a.m. to 9 p.m. and noon to 7 p.m., respectively. The difference in on-peak and off-peak prices varies by season and rate, ranging from on-peak prices that are 2.6 to 4.0 times the off-peak prices.

Q. What on-peak hours does APS propose?

A. APS proposes to consolidate the on-peak hours to 3 p.m. to 8 p.m. weekdays, excluding designated holidays, and to reduce the TOU price difference so that on peak prices are 1.2 to 1.9 times the off-peak prices for the various rate options. As explained by APS witness Miessner on pages 33-34 of his Direct Testimony, the change in on-peak hours better reflects APS's system peak hours.

Q. What is the so-called "duck curve"?

A. The "duck curve" is a graph of demand on the electric system which reflects the impact of the dramatic increase in distributed solar production during the day, which represents the belly of the duck. As solar production ramps down later in the day, customer load increases going into the evening. This is the neck of the duck. This phenomenon is described in the Direct Testimony of APS witness Miessner and in the context of APS's load during various seasons is addressed by APS witness Wilde. As explained by APS witness Wilde at page 4 of his Direct Testimony:

> Non-summer net demand drops in the middle of the day when solar is producing, creating a steep ramp down into the mid-day hours and back up into the peak evening hours when solar shuts off and other resources need to be started to meet peak demand. In California, they call this non-summer load shape the "duck curve" because it has a tail, a belly in the middle, and a head at the end of the day when net customer demand is high.

APS witness Miessner states at pages 34-35 of his Direct Testimony that the Company's proposed TOU hours of 3 p.m. to 8 p.m. address the "duck curve" by encouraging usage to be shifted into the belly of the duck (noon to 3 p.m.) and discourages usage during the peak "neck of the duck" hours.

Q. Has APS proposed adding holidays to the residential TOU rates?

A. Yes. As described on page 35 of his Direct Testimony, APS witness Miessner states that currently, there are 6 holidays that are included in the off-peak hours for some residential time-of-use rates: New Year's Day, Memorial Day, Labor Day, Independence Day, Thanksgiving, and Christmas. APS proposes that these holidays will be applied to all of the new residential time-of-use rates, along with four new holidays: Martin Luther King Day, Presidents Day, Cesar Chavez Day, which is March 31, and Veterans Day.

Q. Has Staff accepted the above-described APS proposals for revised on-peak hours and additional holidays for residential TOU rates?

A. Partially. Staff recommends on peak hours between 2pm and 7 pm on weekdays. Staff also does not take exception to APS's proposal to include the four additional holidays.

I. APS Proposal to Discontinue the Electric Vehicle Rate

Q. What electric vehicle charging rate does APS currently offer?

A. Currently, APS offers an electric vehicle charging rate, ET-EV, which is designed to encourage customers to charge their vehicles during the nighttime and early morning hours. The ET-EV rate creates a super off-peak period of 11 p.m. to 5 a.m. weekdays, with a lower kWh energy price. As APS witness Miessner explains at page 35 of his Direct Testimony: "The concern is that, under the other existing rate options, customers may come home and begin charging their electrical vehicles at 7 p.m. and put significant pressure on the transformer and distribution feeder capacity in their neighborhood."

Q. What reason does APS give for its recommendation to discontinue the electric vehicle rate?

A. APS witness Miessner states at page 35 of his Direct Testimony that APS believes that the proposed demand rate options will provide ample incentive for customers to delay charging their electric vehicles until after 8 p.m. Therefore, a special electric vehicle rate is no longer needed.

Q. Do other Arizona utilities currently offer an electric vehicle charging rate?

A. Yes. For example, Tucson Electric Power Company ("TEP") offers an electric vehicle discount to customers of record who own and operate a highway approved electric vehicle, and who are on an open residential Time-Of Use tariff. (See tep.com for information on TOU tariffs). The electric vehicle discount will be a 5% reduction to the Power Supply Charges during the off-peak periods. Power Supply Charges are the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause ("PPFAC"), as defined in TEP's PPFAC Plan of Administration.[9]

Q. How many customers has APS had on Rate ET-EV and what amount of annual revenue does APS show for this rate?

A. APS's proof of revenue shows approximately $528,000 revenue in the test year from Rate ET-EV and 218 customers.

[9] See, e.g., https://www.tep.com/doc/tep-electric-vehicle-discount-application.pdf

Q. Does Staff agree with the APS proposal to discontinue the electric vehicle charging rate, Rate ET-EV?

A. No. Staff believes there is merit in continuing the ET-EV rate as an option that is available for customers with electric vehicles to choose.

Q. Has Staff developed an updated revenue requirement for Rate ET-EV, corresponding with the Staff's adjusted CCoSS results?

A. Yes. Staff has developed an updated illustrative Rate ET-EV, corresponding with the Staff's adjusted CCoSS and revenue allocation results. As shown on Attachment RCS-13, page 2 of 2, the current adjusted amount of revenue being collected by the ET-EV rate would be increased by 11.18 percent.

J. Limited Income Bill Program

Q. Please discuss APS's limited bill program.

A. APS currently offers two bill-discount programs for customers with limited income. The Energy Support Program (ESP"), also known as the E-3 rate rider, provides bill discounts for customers that are within 150% of the federal poverty level. The Medical Care Equipment Support Program ("MCESP"), also known as the E-4 rate rider, provides a higher bill discount for similarly situated customers with certain qualifying medical equipment that uses a lot of electricity. The E-3 and E-4 programs had a combined participation during 2015 of more than 88,000 customers and funding of $35.6 million, mostly in the E-3 program.[10]

Q. What funding increase is APS proposing for those programs?

A. As described in the Direct Testimony of APS witness Miessner at page 39, APS proposes pro forma adjustments to Test Year revenue and costs to provide funding for program growth

[10] See the Direct Testimony of APS witness Derstine at page 22 and the Direct Testimony of APS witness Miessner at page 39. *CHECK

through mid-year 2017 when new rates are expected to be implemented which amounts to an additional revenue requirement of $12.7 million. This funding consists of an $11.9 million revenue adjustment for additional discounts and an $800,000 cost adjustment for additional administration and marketing costs, which includes income verification expenses to ensure that the program participants are qualified. APS proposes to recover these costs from all customer classes, allocated on kWh, and collected through the System Benefits Charge, which is the current mechanism for recovering these program costs.

Q. Has Staff accepted APS's proposed amount of increased funding for these programs?

A. Yes. In computing APS's revenue requirement, Staff accepted APS's proposed amount of increased funding for these programs.

Q. What changes in the discount structure is APS proposing?

A. As described in the Direct Testimony of APS witness Miessner at pages 39-40, APS proposes to replace the current percentage-of-bill discount structure with a flat $34 discount per month for all customers during the Test Year. Similarly the tiered discounts for the E-4 program will be converted to a flat $57 discount per month, which also reflects the average discount for that program today. In addition, the discounts will be converted to daily discount amounts of $1.12 and $1.87 respectively and capped at 80% of the customer's bill before taxes and other governmental fees.

Q. Has APS provided information on how its limited income customer discounts compare with other Arizona electric utilities?

A. Yes. At page 40 of his Direct Testimony, APS witness Miessner indicates that SRP offers a discount of $21 per summer and summer peak billing cycles, and a $20 discount per winter billing cycle, and that Tucson Electric Power Company ("TEP) currently has a $9 discount or a grandfathered discounted limited income retail rate and TEP proposed to increase this discount to $15 in their most recent rate case, Docket No. E-01933A-15-0322. In comparison with those, APS's current and proposed discounts are larger.

Q. What is Staff's recommendation concerning the APS-proposed limited income customer discounts?

A. Staff believes there is merit in having the updated funding levels that APS has proposed, and in having a flat $57 discount per month discount. However, as noted above, Staff is not convinced that the three-part residential rate design proposed by APS should be mandatory. Staff recommends that residential customers have choices, and not be involuntarily transitioned onto three-part rates with demand charges.

K. Experimental Dynamic Rate Riders

Q. What dynamic pricing riders does APS currently offer?

A. APS currently offers a peak event pricing and peak time rebate, which provide an extra incentive for customers to be able to respond to extremely high load conditions and system emergencies during core summer months. As explained by APS witness Miessner at page 40 of his Direct Testimony, both programs apply a price signal or incentive during a limited number of critical days as determined by the Company. Customers can save on their bill by reducing usage during these critical periods, beyond what they are already reducing through their time-of-use or demand rate. APS has been testing those two programs, along with a super-peak TOU rate that has a higher TOU price in the late afternoon and early evening day during core summer months.

Because it has been easier to implement and produced better demand response, APS proposes to retain the peak pricing rate rider, but to discontinue to the peak time rebate rider and the super peak TOU rate. APS proposes to revise the critical hours from the current 2 p.m. to 7 p.m. to the same 3 p.m. to 8 p.m. TOU on-peak period that APS has proposed for its three-part residential rates.

Q. Is Staff taking exception to any aspects of these APS proposals?

A. No. Staff does not take exception to the APS proposals to retain the peak pricing rate rider, and discontinue the other two experimental programs. Cancelling experimental riders after they have served their useful purpose is appropriate, as is retaining ones that continue to serve a useful function. Staff agrees with APS's proposed revision to the critical hours to 3 p.m. to 8 p.m.

L. Flat Bill Option

Q. What is APS proposing for a flat bill option?

A. As described by APS witness Miessner at pages 42-43 of his Direct Testimony, APS proposes to make a flat bill option available to customers on Rates R-1, R-2, R-3, and R-XS. The flat bill option would not be available to partial requirements customers with onsite generation, customers who do not have an AMI meter, customers on a limited-income discount, customers with less than 12 months of AMI billing history, or extremely large or small customers whose bills would be too difficult to estimate.

Initially, APS proposes to limit participation to 10,000 customers to test the concept, but APS proposes that it could raise or eliminate the cap with notification to Staff.

Under the program, customers pay a pre-determined flat bill each month that is based on the underlying retail rate, the billing determinants from the prior year and any expected increases in annual adjustors, plus a 15% "hedge premium" to reflect potential increases in kWh usage or kW demand during the year. APS proposes that the flat bill would be re-calculated each year based on the customer's new prior year kWh and kW billing determinants and the new expected adjustor rates.

As proposed by APS, there would be no true-up to the customer's underlying calculated bill. APS proposes to track the difference between the flat bill and the underlying calculated bill. If that difference exceeds a 30% threshold on a cumulative month basis, the customer's flat bill amount would be reset for the remainder of the year to reflect the difference.

APS proposes to administer the program on a calendar year cycle. Customers can enroll in or drop out of the program during an open enrollment period in the fourth quarter of the year. The customer's flat bill would be computed based on their prior 12 monthly billing information.

Q. Please discuss Staff's analysis of the APS-proposed flat bill rider program.

A. Staff believes that the flat bill option idea may have merit. However, Staff has concerns that the APS proposal to include a 15% "hedge premium" may result in over-charging customers, particularly since there is no true-up at the end of the year. Staff notes that the program as proposed by APS includes a separate reset provision that would apply if differences between the flat bill and underlying calculated bill exceed a 30% threshold. Staff would support the APS-proposed flat bill program without the 15% "hedge premium" or, in the alternative, with that 15% premium being refundable to the participating customer in full to the extent that the customer's kWh usage and kW demand did not increase during the year or refundable in part, proportionally, if the customer's usage and demand increased by less than 15%.

M. APS's Proposed Transition of Customers to the New Residential Rate Design

Q. What transition period is proposed by APS for the new residential rate design?

A. In order to inform customers about the new rates, APS proposes to implement them in a structured manner over a transition period following the Commission's decision in this rate case. APS witness Derstine at pages 16-17 of her Direct Testimony states that APS plans on transitioning its customers to the new rate plans proposed in this case in phases. APS will move customers to the new plans based upon their billing cycle. She indicates that no existing residential customers will be migrated during the three peak summer months of June, July, and August, 2017. Prior to moving any customers to new service plans, APS will analyze the customer's prior year's usage and determine which of the new rate plans is the best for the customer. APS will move all residential customers to the plan that is best for them, provided they are eligible for that plan. However, once the new rate plans first go into effect, a customer may choose any of the new plans. Customers do not have to wait to be migrated and can elect any plan that they are eligible for, not just the rate APS believes would be the best option for them. APS anticipates that all residential customers will be migrated to the new plans within 9 to 12 months of the date a decision is entered in this case.

Prior to migrating any customer, APS will send the customer a customized letter, explaining that APS has done an analysis of their account and will be automatically moving them to the plan that is best for them based upon their usage history. The communication from APS to the customer will also contain behavioral tips for saving money on the new plans, focusing on Shift, Stagger and Save, as described above and in Attachment SLD-5DR to APS witness Derstine's Direct Testimony. After sending the initial letter and in conjunction with the time they are moved to the new plan, APS indicates that the customers will be sent an additional notice reminding them their plan has changed. The reminder notice will be sent via bill insert and email (for aps.com registered customers). Customers will also be encouraged to visit aps.com for more information about the new plans and options.

APS witness Miessner states at page 47 of his Direct Testimony that:

> During the transition period, residential customers will be billed under the current rate schedules, which will be revised to reflect the increased revenue requirement approved for the residential class. All customers will initially be served under the corresponding transitional rate - E-12 customers on the E-12 transitional rate and so on. So there will be no need to immediately place a customer on a new rate at the conclusion of the rate case. The rates will be frozen so that once a customer either chooses a new rate option or is placed on one, they may not return to the frozen rate. After the transition period, the transitional rates will be cancelled. The revised existing rate schedules are provided as part of the Company's SFRs.

Q. Does Staff agree with the transition proposed by APS?

A. No. Staff disagrees with APS's proposal to involuntarily migrate all but very small residential customers onto three-part rates. Staff supports an orderly transition along with customer education about the new rate structure and customer choice. However, Staff does not recommend that APS be allowed to impose three-part rates on all residential customers having usage above 600 kWh per month. Rather, Staff recommends that APS educate customers about the new rate options, and how customers could save by modifying their usage and voluntarily selecting one of the three-part rates. Staff recommends that all of APS's residential customers continue to have choices, including an option of a two-part rate.

VII. GENERAL SERVICE RATES

A. APS's Current General Service Rates and APS's Proposed Changes

Q. Please discuss APS's current general service rates.

A. APS's General Service customer class includes all non-residential customers except irrigation and outdoor lighting customers. Businesses, schools, universities, hospitals, manufacturers, and governmental accounts are examples of general service customers. APS currently offers a number of rate offerings for general service customers including:

- Standard rates for extra-small, small, medium, large, and extra-large customers (E-32);
- Time-of-use rates for these same customer groups (E-32 TOU);
- Time-of-use rates for schools (GS-Schools M and L);
- A frozen time-of-use rate for houses of worship (E-20);
- Rates for power plants that uses some retail service (E-36 XL and M); and
- An unmetered service rate (E-30).

APS also offers several rate riders for general service customers, including:

- Rate Rider Schedules E-56 and E-56 R for partial requirements service;
- Rate Rider Schedules EPR-2 and EPR-6 for partial requirements service for certain qualifying renewable generation;
- Experimental Rate Rider AG-1;
- Rate Rider Schedule PPR for preference power;
- Rate Rider Schedule IRR for interruptible rates; and
- Rate Rider Schedule SGSP, a schools and government solar program.

Q. What changes is APS proposing for General Service Rates?

A. As explained on page 49 of APS witness Miessner's Direct Testimony, the Company is proposing the following changes and additions to General Service Rates:

- Increase the rates to reflect the requested increase in revenue requirements for the class;
- Increase the basic service charges;
- Modify rates E-32 XS (extra-small) and E-32TOU XS by including a demand charge and simplify the kWh charges by eliminating the second tier rates. Also, change the qualification for these rates to be consistent with other general service rates;
- Reduce the number of on-peak hours for the E-32 TOU rates;
- Reduce the gap to cost of service for rates E-20 and reduce the difference from the alternative E-32 rate options;
- Cancel rate rider E-54 for seasonal service;
- Discontinue the AG-1 experimental rate rider for buy-through power;
- Add a new optional aggregation discount for large customers with multiple sites; and
- Add a new rate for customers with extra high load factors.

B. Rates E-32 XS (extra-small) and E-32TOU XS

Q. What Demand Charge does APS propose to add to Rates E-32 XS and E-32TOU XS?

A. Similar to its residential rate proposals, the Company proposes Three-PartRates for Rates E-32 XS and E-32TOU XS. For Rate E-32 XS, APS proposes including adding a Demand Charge of $6.90 per kW per month for secondary level service and to increase the Basic Service Charge from $20.44 to $35.28. APS proposes demand charges for E-32TOU XS of $4.546 on-peak and $2.599 off-peak for secondary service.

Q. Does Staff agree with that APS proposal?

A. Not completely. Similar to the residential rate proposals, Staff recommends that small General Service customers should also be able to choose to have a Two-Part Rate. Staff opposes APS's proposal to involuntarily impose Three-Part Rates on small General Service customers. Staff supports APS's proposal to offer a Three-Part Rate E-32 XS and Rate E-32TOU XS, but Staff recommends that the small General Service customers should have a choice between Two-Part and Three-Part rate options.

Q. Does Staff agree with APS's proposal to eliminate the second tier of the extra-small General Service rates?

A. Yes. Currently, the extra-small General Service rates have a first-tier kWh charge for the first 5,000 kWh in a month and a lower second-tier charge for all other kWh consumption. Staff agrees with APS's proposal to reduce the first-tier kWh charge and eliminate the second because very few extra-small customers reach the 5,000 kWh threshold in a month and because the second tier adds undue complexity to the rates and is unnecessary.

Q. Does Staff agree with APS's proposal to change the on-peak period for the extra-small general service TOU rates?

A. Yes. Staff agrees with APS's proposal to use an on-peak TOU period of 3 p.m. to 8 p.m. weekdays, without any holiday exemptions, for the extra-small General Service TOU rates.

Q. Has Staff developed illustrative rates for extra small general service customers using Staff's adjusted cost of service and revenue allocation?

A. Yes. Similar to some of the comments regarding residential rate design, Staff is concerned that there is a mismatch in the way the basic service charge is presented in existing rate structures for extra small general service customers. Subject to testing for customer bill impacts and the concept of gradualism, Staff recommends that an optimal rate structure would have a higher basic service charge for the standard two-part rate, a basic service charge for the TOU rate that is lower than the basic service charge for the standard two-part rate, and a basic service charge for the three-part rates that is lower than the basic service charge for the TOU rate. Under the current structure of basic service charges between alternative rates such as these, customers are incented to utilize a standard two-part rate over the alternative time varying rate. Staff believes, this is an issue that needs to be addressed and is recommending that over time basic service charges be higher in two-part rates then in the alternative TOU and three-part rates. Exhibit RCS-14 illustrates how the Staff adjusted revenue allocation and the establishment of basic service charges could be used to establish new two-part rates for extra small general service rates E-32 XS and E-32 TOU XS. Exhibit RCS-15 presents similar illustrative rate design for three-part versions of these rates that include a component for demand charges.

C. Proposed Cancellation of Rate Rider E-54

Q. Does Staff agree with APS's proposal to cancel rate rider E-54, which is a seasonal service alternative minimum bill rider?

A. Yes. APS has indicated that there are currently no customers participating in this rate rider. Moreover, it is no longer necessary or beneficial to customers given the changes to rate E-32 L in APS's last general rate case.

D. Experimental AG-1 Rate

Q. What is the APS Experimental AG-1 Rate?

A. Pursuant to the Settlement Agreement in APS's last base rate case that was approved in Decision No. 73183, APS offered an experimental buy-through rate for the generation portion of the bill for large and extra large commercial and industrial customers. The program was limited to 200 MW of total participation, to ideally be split equally between the large and extra-large customer groups.

Q. Have APS customers been using the Experimental AG-1 Rate?

A. Yes. As indicated by APS witness Snook on page 43 of his Direct Testimony, customer interest in the program exceeded the program size limits, so APS conducted a lottery to select participants for the experimental program. The program is fully subscribed.

Q. Has the sunset date for the Experimental AG-1 Rate been extended?

A. Yes. Initially, the program had a sunset date of June 30, 2016, but the date was extended by the Commission in its Decision No. 75322 (November 25, 2015) to coincide with the ultimate rate effective date of the Decision in this rate case.

Q. Has APS identified concerns with the Experimental AG-1 Rate?

A. Yes. APS has raised concerns that the Experimental AG-1 Rate has not enabled APS to recover its costs. APS witness Snook states on page 44 of his Direct Testimony that APS believes the AG-1 program has significant flaws and shifts unreasonable revenue responsibility to other customers. He states that APS has had unmitigated lost margins from the AG-1 program every year it has been in place. Consequently, APS does not view the Experimental AG-1 Rate as a sustainable program.

Q. What does APS propose for the Experimental AG-1 rate?

A. APS proposes that it not be renewed.

Q. In the event that a buy-through program like the Experimental AG-1 rate were to continue to be required by the Commission to be offered by APS, does APS recommend some changes to the current program?

A. Yes. APS recommends several modifications to ensure that AG-1 customers directly pay a greater share of APS's cost of providing them service. The specific changes recommended by

APS are listed in Mr. Snook's Direct Testimony at pages 44-45. However, even with such modifications, Mr. Snook states at page 46 of his Direct Testimony that APS does not believe that the benefits of a renewed AG-1 program outweigh the risks.

Q. Does Staff support the renewal of the Experimental AG-1 Rate?

A. Staff recognizes that the Experimental AG-1 rate has been a popular program with the eligible APS customers. Thus, there is likely to be continued interest in the program from the customers who are currently participating, as well as from other APS customers who have wanted to participate but could not, due to the program limitations to 200 MW of total participation. On the other hand, Staff acknowledges APS's significant concerns about significant program design issues. In particular, Staff is concerned about shifts of revenue requirement responsibility to other APS customers, which was one of the main concerns identified by APS. Staff shares APS's concerns that the Experimental AG-1 Rate in its current form is not sustainable. Staff agrees with APS that if a program similar to the AG-1 Rate were to be provided, a number of modifications to the current version of the Experimental AG-1 Rate would be needed. Because of such concerns, Staff is not opposed to APS's request to not renew the Experimental AG-1 Rate. Staff recommends that APS continue to work with the large customers who are on the AG-1 Rate and who would be eligible for the AG-1 rate but for the program limitations, and to see if modifications can be developed to provide for a buy-through rate that addresses the concerns noted above. Staff does not recommend approval of a AG-1 type rate unless it can be demonstrated that no other customers will be harmed as a result of the program.

E. Economic Development, Service Schedule 9

Q. What is APS proposing for a new Economic Development rate provision, Service Schedule 9?

A. As described by APS witness Snook at pages 47-48 of his Direct Testimony:

> The proposed Service Schedule 9 is intended to support commercial and industrial economic development in the APS service territory. The Company proposes to provide a bill discount over a period up to six years for qualifying new or expanding customers. Eligible customers include new customer sites and significant net expansions for existing sites served under extra-large general service rates E-34 and E-35, with a minimum new load of 1,000 kW for existing customers and 2,000 kW for new customers, and monthly average load factors of at least 55%. The discount would be specific to each customer, within the following parameters: 1) the discount does not exceed 25% and 2) is no less than APS's marginal cost of providing service. APS will file agreements executed under Service Schedule 9 with the Commission Staff in a compliance filing. APS envisions that the discount would typically be structured on a declining annual basis over the term. The eligible customer would also be encouraged to participate in the Company's energy efficiency program, demand response program, or renewable energy programs to help minimize any system peak impact from the new load. Total participation under this service would be limited to 100 MW of load or 50 new customers, whichever is less (on a MW basis).

Q. What has APS proposed for an Economic Development rate?

A. As described by APS witness Snook at pages 47-48 of his Direct Testimony, the APS-proposed Schedule 9 is intended to support commercial and industrial economic development in APS's service territory. APS proposes to provide a bill discount over a period of up to six years for qualifying new or expanding customers.

Q. What eligibility requirements does APS propose for the Economic Development rate?

A. APS proposes that eligible customers include new customer sites and significant net expansions for existing sites served under extra-large general service rates E-34 and E-35, with a minimum new load of 1,000 kW for existing customers and 2,000 kW for new customers, and monthly average load factors of at least 55%. The APS-proposed eligibility requirements are set forth in additional detail in Section 1 of APS's proposed Service Schedule 9.

Q. What features of the Economic Development rate does APS propose to avoid cross-subsidization?

A. APS proposes that the discount be specific to each qualifying customer and that (1) the discount does not exceed 25% and (2) the discounted rate is no less than APS's marginal cost of providing service. APS further proposes that it would file the agreements that it executes with customers pursuant to Schedule 9 with the Commission Staff in a compliance filing.

Q. What are some of the other features of APS's proposed Economic Development rate program?

A. APS witness Snook also states that the Company envisions that the discount would typically be structured to decline annually over the term. Moreover, the eligible customer would be encouraged by APS to participate in the Company's energy efficiency program, demand response program, or renewable energy programs to help minimize any system peak impact from the new load. Finally, APS proposes to limit participation in the Economic Development rate program to 100 MW of load or 50 new customers, whichever is less (on an MW basis).

Q. Does Staff support the APS proposal for an Economic Development rate?

A. Yes. Staff supports the APS proposal for an Economic Development rate under Service Schedule 9.

Q. Does Staff have any recommendations concerning the APS compliance filings?

A. Yes. When APS files the customer agreements, in addition to providing Staff with a copy of the "Customer Characteristics Report" listed in Section 4 of the APS-proposed Service Schedule 9, APS should provide Staff with information estimating the impact on peak demand from the new load, as well as information clearly demonstrating that (1) the discount does not exceed 25% and (2) the discounted rate is no less than APS's marginal cost of providing service.

Q. Does Staff have any recommendations concerning the "Conflict of Interest" provisions in Section 2 of the APS-proposed Service Schedule 9?

A. Yes. The APS-proposed Conflict of Interest provisions include APS submitting an affidavit to the Commission that includes statements that no current officer or director of Pinnacle West Capital Corporation or any of its subsidiaries has a direct or indirect interest in the Customer or in any entity which has provided substantial services to the Customer in connection with a proposed agreement under this schedule. Staff recommends that this Conflict of Interest provision be strengthened by including in the statement not only current officers and directors, but also any persons who have been officers or directors of Pinnacle West Capital Corporation or any of its subsidiaries within the three-year period prior to the Service Schedule 9 agreement.

F. Extra-High Load Factor Rate

Q. Please discuss APS' proposal for a new Extra-High Load Factor ("XHLF") Rate.

A. APS witness Snook discusses this APS proposal at pages 46-47 of his Direct Testimony. To qualify for the new XHLF rate, the customer must have a monthly average load factor of 92% in nine of the last twelve months, on a rolling basis. In addition, different than other extra-large rate schedules, the minimum size qualification is 5,000 kW or greater, rather than

3,000 kW. A few additional features of the XHLF rate would be available to customers with a minimum size of 15,000 kW. For example, APS is proposing the option of qualifying for transmission level service through a contribution in aid of construction ("CIAC"), rather than outright purchase of the facilities, at the 15,000 kW threshold. This option will require the customer to also enter into a maintenance contract and share in the cost of replacing any equipment that is necessary. As part of this option, APS will also offer to finance the CIAC at APS's WACC established in its most recent rate case for a period not to exceed ten years. Additional details of APS's proposed XHLF Rate Schedule have been provided by APS in its Standard Filing Requirement Information, under "General Service."

Q. Does Staff support APS's request for a new XHLF rate?

A. Staff believes there is merit in the APS-proposed new XHLF Rate. Staff has adjusted the amount of revenue that should be collected an XHLF rate (based on using Staff's adjusted CCoSS results) in Attachment RCS-13, page 2, to $17.508 million. This is a 4.36 percent increase over the adjusted amount of current revenue listed by APS of $16.776 million, and is lower than the APS-proposed amount of $24.650 million.

VIII. RATES FOR IRRIGATION/WATER PUMPING, OUTDOOR LIGHTING, AND DUSK-TO-DAWN LIGHTING SERVICE

Q. Does Staff agree with the rates proposed by APS for Irrigation/Water Pumping, Outdoor Lighting, and Dusk-To-Dawn Lighting Service?

A. No. However, as shown on Attachment RCS-12 and RCS-13, the differences for these rates between Staff and APS relate to the Staff's recommendation to use a lower jurisdictional revenue requirement.

IX. OTHER APS-PROPOSED RATE CHANGES

A. Flagstaff Solar Experimental Rate Rider, Rate Schedule CMPW-01

Q. What is the Flagstaff Solar Experimental Rate Rider?

A. As explained in APS witness Miessner's Direct Testimony at page 42, this is an experiment involving 125 residential customers on a single feeder in APS's Northern region. APS installed and owns the rooftop solar units, which are hooked up directly to the grid and do not serve the load in the home. The program has been ongoing for approximately five years, and APS has completed the grid impact assessments. Therefore, APS proposes to consolidate the Flagstaff Solar Experiment into the Solar Partner Program, with the $30 per month bill credit for renting the customer's roof. Because of the consolidation, APS proposes to cancel the Flagstaff experimental Rate Schedule CMPW-01.

Q. Does Staff agree with this APS proposal?

A. Staff does not take exception to this APS proposal. Cancelling experimental riders after they have served their useful purpose is appropriate.

B. Changes to Service Schedule 1 Charges

Q. What changes is APS proposing to Service Schedule 1 charges?

A. APS witness Miessner's Direct Testimony at pages 59-60 lists the following Service Schedule 1 current rates, APS's proposed charges and the changes:

Service Schedule 1 - Statement of Charges - Proposed Changes			
Description	Proposed Charges	Current Charges	Difference
Residential Service Establishment Charge	$ 8.00	$ 25.00	$ (17.00)
Nonresidential Service Establishment Charge	$ 33.00	$ 35.00	$ (2.00)
After hours Charge –Residential Standard Metering	$ 8.00	$ 75.00	$ (67.00)
After hours Charge –Residential Non-Standard Metering	$ 137.00	$ 75.00	$ 62.00
After hours Charge –Nonresidential	$ 164.00	$ 75.00	$ 89.00
Same Day Connect Charge	$ 87.00	$ 75.00	$ 12.00
Non-standard Connect Charge (per crew person, per hour)	$ 164.00	$ 75.00	$ 89.00
Electronically Transmitted Payment Discount	$ (0.48)	$ (0.48)	$ -
Dishonored Payment Fee	$ 15.00	$ 15.00	$ -
Field Call Charge	$ 10.00	$ 15.00	$ (5.00)
Overhead Reconnection Charge	$ 89.00	$ 96.50	$ (7.50)
Underground Reconnection Charge	$ 135.00	$115.00	$ 20.00
Non-Standard Metering- Monthly Meter Reading	$ 15.00		$ 15.00
Set-up fee for customer with existing AMI meter	$ 70.00		$ 70.00
Set-up fee for customer without existing AMI meter	$ 50.00		$ 50.00
Meter Reread	$ 14.00	$ 16.50	$ (2.50)
Meter test in shop	$ 44.00	$ 30.00	$ 14.00
Meter test at site	$ 93.00	$ 50.00	$ 43.00
Trip Charge - Residential	$ 22.00	$ 16.00	$ 6.00
Trip Charge - Nonresidential	$ 26.00	$ 16.00	$ 10.00

Overall, the changes proposed by APS to these charges are anticipated to result in approximately $3.9 million in reduced annual revenue, which is reflected in the APS pro forma adjustment to Test Year revenue detailed in Attachment CAM-07DR.

Q. Does Staff have issues with some of the APS-proposed Schedule 1 fees?

A. Yes. Staff recommends that the APS-proposed "set-up" fees of $70 and $50 for customers to opt-out of having an AMI meter be rejected.

Additionally, Staff questioned the cost support provided by APS for the $87 Same Day Connect Charge and the $164 Non-standard Connect Charge (per crew person per hour). In response to such Staff inquiries, APS has indicated that a correction is needed.

C. AMI-Meter Opt Out Fees

Q. Please discuss the charges proposed by APS for customers who opt out of having AMI meters.

A. The AMI opt-out option allows customers to be served with a digital meter and manual meter reading instead of the AMI system. Details of the meter technology and related program information are provided in the Direct Testimony of APS witness Bordenkircher. There are additional charges to cover the one-time special installation cost and the monthly cost of reading the meter manually with APS personnel rather than automatically through the AMI communication network. APS proposes a one-time installation charge of $70 for customers with an existing AMI meter ($50 for customers without an existing AMI meter), and an on-going meter reading charge of $15 per month.

Q. How many customers does APS have that have opted out of having AMI meters?

A. APS witness Bordenkircher's Direct Testimony at page 10 shows that in 2015 APS had 16,568 customers with non-standard meters:

Region of Arizona		**# of Meters**
Northwestern	Prescott, Cottonwood, Sedona, Dewey, Flagstaff	10,352
Metro Phoenix		3,610
Northeastern	Payson, Show Low, Snowflake	1,856
Southeastern	Casa Grande, Bisbee, Douglas, Globe, Miami	518
Southwestern	Yuma, Parker, San Luis	232
Grand Total		**16,568**

In the response to Staff 9.18, APS showed that as of September 30, 2016, 15,890 customers had elected to not have an AMI meter.

Q. What concerns does Staff have concerning the AMI opt-out charges?

A. Staff is concerned with determining whether or not the opt-out fees are cost-based and appropriate.

Q. Has Staff reviewed the cost support provided by APS for these charges?

A. Yes. Staff has reviewed the information provided by APS for these charges including the information provided in APS witness Bordenkircher's testimony. APS claims that a residential customer that chose to opt-out created additional meter reading related costs to APS during the Test Year of $232.15; this is comprised of $66.79 for the initial set-up plus an additional $13.78 per month. APS claims that a commercial customer's additional cost in 2015 was $499.95; this is comprised of $334.59 for the initial setup plus an additional $13.78 per month. Mr. Bordenkircher states at page 10 of his Direct Testimony that the total cost and expenses attributable to meter reading for non-AMI meters in the Test Year was $3,071,131. He indicates that this cost includes expenses such as: the additional transportation costs and wear and tear on vehicles; additional employees or additional employee time allocation to manually read meters and input the information into the billing system; and additional supplies, equipment and technology.

Q. Are there some customers, who, under APS's proposal would not have the option to opt-out of having an AMI meter?

A. Yes. According to the Direct Testimony of Scott Bordenkircher, rooftop solar customers and non-residential customers would not have the option to opt out. APS would not allow rooftop solar customers to opt-out of having an AMI meter because it is critical to APS's grid reliability and load forecasting accuracy that APS have current production data from all rooftop solar systems. APS has also stated that non-residential customers would not be allowed to opt-out because they are larger customers with more complex billing structures that require the sophistication of an AMI meter.

Q. Why does APS assert that it is appropriate to charge customers refusing "smart" meters additional charges for meter reading and set-up when other customers will be receiving that same service at no extra charge?

A. APS responded to this question in Woodward 2.10(d) as follows:

> Customers who specifically choose to opt out of APS's standard metering when they otherwise could be successfully served via standard metering are causing additional costs for the utility that it would otherwise not have. It is therefore appropriate for those customers who make that choice to bear those costs.

Q. Why does APS assert that it is appropriate to charge customers refusing "smart" meters the cost of the "smart" meters system they are not using, the cost of manually reading their meters, plus the cost of manually reading these customer meters that cannot be serviced by a "smart" meter.

A. APS responded as follows to this question in Woodward 2.10(e):

> APS's metering cost structure includes the costs associated with metering all customers via AMI as well the small number of customers who cannot (through any choice of their own) be metered via AMI. These costs are shared by all APS customers. Customers who specifically choose to opt out of APS's standard metering when they otherwise could be successfully served via standard metering are causing additional costs for the utility that would otherwise not have. It is therefore appropriate for those customers who make the choice to bear those costs.

Q. Did APS provide information showing the cost basis for its proposed AMI meter opt-out charges?

A. Yes. APS provided information showing the cost basis for its proposed AMI meter opt-out charges in Scott Bordenkircher's direct testimony and in response to Staff 9.18.

Q. How does the AMI opt-out option proposed by APS compare to charges that are similar for other Arizona utility companies?

A. In 2013, Tuscan Electric Power (TEP) had a rate case (Docket No. E-01933A-12-0291) in which they proposed similar fees that APS is proposing in this rate case regarding the AMI opt-out option. Decision No. 73912 in regards to that case states that the Commission currently has an on-going investigation docket on safety, privacy and health issues concerning the use of smart meters, Docket No. E-00000C-11-0328. TEP's rate case was held open for AMI opt-out issue until the Commission's investigation concluded and decide on the appropriateness of TEP's opt-out charges and tariffs after the Commission's decision was entered into Docket E-00000C-11-0328. As of now, that investigation is still open. Therefore, TEP's issue regarding the opt-out option is still undecided. In TEP's 2015 rate case (Docket No. E-01933A-15-0322), Staff recommended in Howard Solganick's Rate Design Direct Testimony, that the costs of a new meter installation should be recouped from the customer requesting a non-standard meter (at the fee for Service Establishment, Reestablishment, or Reconnection of Service under usual operating procedures During Regular Business Hours) along with the monthly reading costs (at the Special Meter Reading Fee). In its rebuttal testimony, TEP agreed with Staff witness Solganick's recommendations. According to TEP's Statement of Charges, the Special Meter Reading Fee is $20, and the Service Establishment, Reestablishment, or Reconnection of Service under usual operating procedures During Regular Business Hours is $32.

Q. What are APS's current fees for a meter installation?

A. In APS's Service Schedule 1 in their Statement of Charges, APS lists their Residential Service Establishment Charge as $25, and their Non-Residential Service Establishment Charge as $35. APS describes their Service Establishment Charge as follows:

> 2.2 <u>Service Establishment and Customer Request for Special Service Charge</u> - A Service Establishment Charge of $25.00 for residential and $35.00 non-residential plus any applicable tax adjustment will be assessed each time Company is requested to establish, reconnect or re-establish electric service to the Customer's Delivery Point, or to make a special read without a disconnect and calculate a bill for a partial month.
>
> 2.2.1 The Customer will additionally be required to pay a trip charge of $16.00 when an authorized Company representative travels to the Customer's site and is unable to complete the Customer's requested services due to lack of access to the Point of Delivery.

Q. What are APS's proposed charges for Service Establishment?

A. APS proposes to reduce the Residential Service Establishment charge to $8 from the current charge level of $25. APS proposes to reduce the Nonresidential Residential Service Establishment charge to $33 from the current charge level of $35.

Q. Has APS provided information concerning its cost of meter installation per unit, and is its installation cost different for AMI and non-AMI meters?

A. Yes. APS's response to Woodward 2.19(d) provided APS's meter cost information as follows:

[HIGHLY CONFIDENTIAL]

[redacted]

[redacted]

[redacted]

[END HIGHLY CONFIDENTIAL]

Q. Does APS distinguish its meter installation costs between whether a meter is an AMI meter or not an AMI meter?

A. No. APS's meter installation costs are based on the meter phase and not upon whether the meter is AMI or non-AMI.

Q. Should the cost for installing a non-AMI meter be more than the cost of installing an AMI meter?

A. No, it should not.

Q. What is Staff's recommendation regarding APS's proposed AMI meter opt-out option?

A. Staff supports the $15 meter reading fee that APS proposes to charge, because APS has reasonably demonstrated that it would incur additional costs associated with meter reading for customers who voluntarily choose to opt-out of having an AMI meter, in comparison to customers who have an AMI meter. Staff views the $15 meter reading fee is cost-based and relates to the additional costs attributable to the customer's choice to not have an AMI meter.

However, Staff does not support the APS-proposed set-up fees of $70 for a customer with an existing AMI meter and $50 for a customer without an existing AMI meter. APS has not demonstrated that its cost of installing a non-AMI meter is different from its costs of installing an AMI meter, thus charging customers who opt-out of having an AMI meter an additional installation or set-up fee is not reasonable. The standard residential and nonresidential Service Establishment Charges should apply regardless of whether the customer has an AMI or non-AMI meter.

D. Same Day Connect Charge and Non-standard Connect Charge

Q. Did the APS-proposed Same Day Connect Charge and Non-standard Connect Charge agree with the cost support that APS provided for those charges?

A. No. The APS-provided cost support for the Non-standard Connect Charge shows $91, rather than the $164 proposed by APS for that charge. In response to an informal inquiry by Staff about this, APS provided the following statement:

> [T]he $91 listed under the blended cost column should be updated to $164.
>
> The primary difference in the Non-Standard connect charge versus the Same Day connect charge is that the Non-Standard is listed at 1 hour of field time instead of two. The blended costs are still the same because the individual charge for that service alone at 2 hours would be higher than $163.43, but the decision was to level the charges at $164 for consistency. In most cases, the field time for the Non-Standard connect is in fact 2 hours, but that was not reflected in this chart.

With this additional explanation from APS, Staff has accepted those charges.

X. RATE STABILIZATION MECHANISM

Q. What does APS propose for a Rate Stabilization Mechanism in the current rate case?

A. Apparently, APS is <u>not</u> proposing adoption of a Rate Stabilization Mechanism in the current rate case. APS witness Snook explains at pages 34-35 of his Direct Testimony that the Company believes that a full revenue decoupling mechanism, which he refers to as a Rate Stabilization Mechanism ("RSM") could have some benefits to the Company and its customers, which he lists on page 35 of his Direct Testimony. However, at page 35, he also states that APS determined that this case was not the appropriate time to propose the RSM. From the discussions in Mr. Snook's testimony, it is apparent that APS is not proposing adoption of full per-customer revenue decoupling or an RSM in the current rate case.

XI. LOST FIXED COST RECOVERY MECHANISM

Q. What is the Lost Fixed Cost Recovery mechanism?

A. The LFCR mechanism provides for the recovery of lost fixed costs, as measured by revenue, associated with the amount of energy efficiency ("EE") savings and distributed generation ("DG") that is authorized by the Commission and determined to have occurred. Costs to be recovered through the LFCR include the portion of transmission costs included in base rates and a portion of distribution costs, other than what is already recovered by (1) the Basic Service Charge and (2) 50% of demand revenues associated with distribution and the base rate portion of transmission.[11]

Q. Is APS proposing revisions to its LFCR?

A. Yes. As described by APS witness Snook on pages 36-37 of his Direct Testimony, APS is proposing some modifications to its existing LFCR, including the following:

- The Company is proposing that the LFCR rate filed on January 15th become effective on the first billing cycle in March each year unless the Commission takes specific action on the LFCR compliance filing.
- The Company is proposing to increase the year over year cap to 2%.
- APS is proposing to update the costs eligible for recovery. Specifically, APS is proposing that the LFCR be modified such that 100% of transmission, distribution and generation costs collected through energy charges are included and 50% of transmission, distribution and generation costs collected through demand charges are included.
- APS is proposing to remove the LFCR opt-out rate option, which APS indicates has proven unnecessary.
- APS is proposing that the adjustment will be no longer be applied to customers' bills as an equal percentage surcharge, but rather as a capacity (demand) charge per kW for customers with a demand rate and as a kWh charge for customers with a two-part rate without demand.

[11] See, ACC Decision No. 73183, Attachment F, page 1.

Q. Has APS provided its revised LFCR Plan of Administration?

A. Yes. APS provided its revised LFCR Plan of Administration in the Standard Filing Requirements.

Q. Why is APS proposing to cancel the LFCR opt-out option?

A. APS witness Meissner states at page 41 of his Direct Testimony that the LFCR opt-out option is typically not beneficial to customers, is not widely subscribed, and in APS's opinion is unnecessary.

Q. What portion of APS's residential customers have elected the LFCR opt-out option?

A. APS's response to Staff 5.5 (attachment APSRC013333) indicates that approximately 0.302 percent of its residential customers have elected the LFCR opt-out option for its 2015 LFCR filing and 0.273 percent of residential customers elected to opt out of the Company's 2014 LFCR filing.

Q. Does Staff agree with those APS-proposed revisions to the LFCR mechanism?

A. Staff agrees with portions of the APS-proposed LFCR modifications and does not agree with other parts.

Staff does not agree with APS's first three proposed changes to the LFCR and recommends that those revisions be rejected.

Concerning the LFCR opt-out option, Staff agrees with APS that this option is not widely subscribed and supports APS's proposal to discontinue the LFCR opt-out as something that customers could elect, commencing with the effective date of new rates in the current APS rate case. However, Staff recommends that customers who have already elected the LFCR opt-out (or who elect this before the effective date for new rates) be allowed to continue under that option.

Staff agrees with APS's proposal that the adjustment no longer be applied to customers' bills as an equal percentage surcharge, but rather as a capacity (demand) charge per kW for customers with a demand rate and as a kWh charge for customers with a two-part rate without demand.

Q. Does Staff have a recommendation about the LFCR filing date and effective date?

A. Yes. Staff would prefer to have actual calendar information available when APS makes its annual LFCR filing. Also, Staff has determined that more time is needed for Staff to review the information and have the Commission approve the new LFCR rates. Staff recommends that new LFCR rates continue to be subject to Commission approval, prior to taking effect. Staff recommends a filing date of February 15 for APS's LFCR compliance filings and that the new LFCR rates take effect, after Commission approval, with the first billing cycle of May each year.

XII. ENVIRONMENTAL IMPROVEMENT SURCHARGE

Q. What is the Environmental Improvement Surcharge (EIS)?

A. The EIS was approved by the Commission in Decision Nos. 69663 and 73183. The EIS recovers the cost associated with investment and expenses for environmental improvements at APS' generation facilities that the ACC has approved for recovery. Approved environmental improvements include those implemented on or after January 1, 2004, for which costs have not been fully recovered under current approved rates, ongoing environmental improvement projects and environmental improvement projects designed to comply with prospective environmental standards required by federal, state, tribal, or local laws or regulations. The EIS Plan of Administration describes the "Qualified Investments" that are allowed under the mechanism. By providing timely and sufficient recovery of the costs of requirement environmental improvement projects, the EIS helps APS make those capital investments and secure capital at a reasonable cost.

Q. What modifications has APS proposed for the EIS?

A. APS witness Snook's Direct Testimony at pages 38-40 describes the modifications being proposed for the EIS, which include:

- Changing the structural cap on cost recovery from a rate to a dollar amount ($0.00016 per kWh to $10M year-over-year).
- Providing for the ability to carry over into subsequent periods any excess EIS adjustment over the annual cap. APS indicates that this addition is consistent with APS's other adjustment mechanisms, including a nominal interest component.
- Inclusion of a balancing account to account for any differences between the allowable EIS adjustment and actual revenues received by the Company through the EIS during the recovery period.

Q. Does Staff agree with those APS-proposed revisions to the EIS mechanism?

A. Staff disagrees with the first two APS proposed revisions. Staff agrees with the APS proposal for a balancing account.

Q. Does Staff recommend an increase in the EIS structural cap on cost recovery?

A. Staff recommends that the structural cap on cost recovery be maintained as a rate and that it apply on a cumulative basis, not a year-over-year basis as APS has requested, but that the rate be increased from the current $0.00016 to a new rate of $0.00050. With the new higher rate and with the rate continuing to be applied as a cumulative structural cap, there is no need for a carry-over of amounts over an annual cap, which was requested by APS.

Q. Have you included selected APS responses to discovery about the EIS with your rate design testimony?

A. Yes. Attachment RCS-16 includes APS's response to Staff 5.56, wherein APS provided its two most recent EIS annual reports.[12] APS's responses to Staff 5.8 and Staff 10.1, both of which contain APS-designated CONFIDENTIAL material, are included in Attachment RCS-17.

Q. Has APS indicated whether it has included costs for the Four Corners SCRs in the EIS?

A. APS witness Snook discusses this at page 40 of his Direct Testimony. He indicates that the costs for the Four Corners SCRs would be Qualified Investments under the EIS mechanism but APS has proposed that the SCR costs be treated separately given the magnitude of the costs for those projects. APS's response to Staff 5.8 similarly indicates that the Four Corners SCR costs of approximately $400 million for the federally mandated environmental projects are not included, and that APS seeks a cost deferral order and step increase in rates to recover the SCR costs.

[12] Note: due to the size of those attachments and the fact that the APS 2016 and 2015 files were made with the Commission under Docket No. E-01345A-1-0224 (Decision No. 73183) on January 28, 2016 and January 30, 2015, respectively, the EIS reports are not included in the attachment.

Q. Does APS's response to Staff 10.1 include projected cost information for the EIS, with and without the Four Corner's SCRs?

A. Yes. Staff reviewed that information, particularly the forecasts for 2017 through 2020, without the Four Corner's SCRs[13] as supporting the reasonableness of raising the cumulative cap to $0.00050.

XIII. TRANSMISSION COST ADJUSTMENT CHARGE

Q. What is the Transmission Cost Adjustment charge?

A. The Transmission Cost Adjustment (TCA) applies to all Standard Offer retail electric schedules.[14] It recovers transmission costs. APS has a Formula Rate mechanism, approved by the Federal Energy Regulatory Commission ("FERC") that is designed to recover transmission costs. Since APS's rates are unbundled, both wholesale and retail customers pay the same transmission rates. The Formula Rates are revised every year. APS's retail customers pay part of the transmission costs in base rates with the TCA rates adjusting each year to account for the changes in the Formula Rate.

Q. Has APS included all of its transmission costs in deriving its test year base rate revenue requirement?

A. Yes. According to APS's response to Staff 5.81, all transmission costs as of the Test Year have been used in the base rate revenue requirement determination.

Q. What modifications is APS proposing to the TCA?

A. As explained by APS witness Snook on page 41 of his Direct Testimony, APS is proposing to modify the TCA by including a balancing account to account for any differences between the

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[13] See, e.g., CONFIDENTIAL APSRC000761, page 1 of 2.

[14] See, e.g., APS Tariff, Adjustment Schedule TCS-1, Transmission Cost Adjustment, Revision No. 12, effective June 1, 2016.

calculated TCA rates and actual revenues received by the Company through the TCA during the recovery period (June through May).

Q. Does APS currently have a reconciliation procedure in place for transmission costs and the TCA?

A. No. As explained in APS's response to Staff 5.68, currently there is no balancing account associated with the TCA and APS does not have a formal reconciliation procedure in practice.

Q. Has APS provided actual transmission costs for recent years and a comparison of what APS was allowed to recover through base rates and the TCA?

A. Yes. In response to Staff 5.69, APS provided actual transmission costs for recent years and a comparison of what APS was allowed to recover through base rates and the TCA for calendar years 2012 through 2015 and partial information for 2016.

Q. Has APS provided information concerning what the Over and Under Recovery balances would have been, had a TCA balancing account been in place?

A. Yes. APS's response to Staff 5.7 lists for years 2008 through 2015 actual billed and allowed recovery of TCA costs, along with the Over or Under Recovery amount for each year. APS had under recoveries in years 2008-2009 and 2011-2014 and had over-recoveries in years 2010 and 2015. APS's response to Staff 5.7 points out that APS's proposal in the current rate case is only for recovery of prospective over or under-recovered amounts through the TCA and not historical amounts.

Q. Does Staff agree with those APS-proposed revisions to the TCA?

A. No. The TCA rates should not change without a corresponding change in the Formula rate mechanism. Since APS's proposal for a revenue balancing account would address only revenues and not costs, APS could over earn if revenues go up and costs go down. It would be difficult to justify that type of change in the Formula rate mechanism with FERC.

Q. Does this conclude your Rate Design Direct Testimony?

A. Yes, it does.

ARIZONA PUBLIC SERVICE COMPANY
ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING DECEMBER 31, 2015
($)

Return

Line #	2015 TY Cost of Service (Adjusted)	ELECTRIC TOTAL	ACC JURISDICTION	ALL OTHER	TOTAL RETAIL	RESIDENTIAL	GENERAL SERVICE	E-221 (Water Pumping)	STREET LIGHTING	DUSK TO DAWN
1										
2	**SUMMARY OF RESULTS**									
3										
4	**DEVELOPMENT OF RATE BASE**									
5	ELECTRIC PLANT IN SERVICE	15,326,435,253	12,962,340,167	2,364,095,086	12,962,340,167	8,099,051,086	4,554,642,478	122,239,266	133,850,295	52,557,042
6	GENERAL & INTANGIBLE PLANT	1,509,541,568	1,400,428,100	109,113,468	1,400,428,100	913,116,365	464,146,198	11,777,669	7,325,948	4,061,919
7	LESS: RESERVE FOR DEPRECIATION	(6,402,411,202)	(5,632,319,059)	(770,092,143)	(5,632,319,059)	(3,511,914,006)	(2,002,097,799)	(52,785,504)	(47,533,720)	(17,988,030)
8	OTHER DEFERRED CREDITS	(1,337,180,000)	(1,292,838,371)	(44,341,629)	(1,292,838,371)	(768,219,184)	(503,174,681)	(12,664,195)	(6,801,831)	(1,978,480)
9	WORKING CASH	(113,623,376)	(93,558,549)	(20,064,827)	(93,558,549)	(58,288,866)	(32,917,689)	(893,500)	(1,054,520)	(403,975)
10	MATERIALS, SUPPLIES & PREPAYMENTS	438,426,790	398,768,143	39,658,647	398,768,143	225,856,548	164,697,669	4,153,353	3,070,544	990,029
11	ACCUM. DEFERRED TAXES	(2,873,411,027)	(2,359,729,334)	(513,681,693)	(2,359,729,334)	(1,503,979,442)	(796,946,649)	(21,719,932)	(26,263,829)	(10,819,481)
12	REGULATORY ASSETS	310,940,000	250,199,222	60,740,778	250,199,222	181,817,468	63,623,483	1,701,159	1,762,326	1,294,787
13	DECOMMISSIONING FUND	735,196,000	731,225,942	3,970,058	731,225,942	434,549,532	285,200,677	7,291,629	3,632,160	551,943
15	MISCELLANEOUS DEFERRED DEBITS	121,338,000	113,265,656	8,072,344	113,265,656	71,286,870	40,082,726	1,006,098	594,776	295,186
16	OPEB	182,625,115	168,753,227	13,871,888	168,753,227	110,070,359	55,890,824	1,418,175	882,962	490,906
17	CUSTOMER ADVANCES	(115,609,383)	(94,903,242)	(20,706,141)	(94,903,242)	(49,850,247)	(44,764,989)	(138,265)	(149,058)	(683)
18	CUSTOMER DEPOSITS	(72,621,690)	(72,621,690)		(72,621,690)	(38,578,117)	(32,616,324)	(706,920)	(511,132)	(209,197)
19	PROFORMA ADJUSTMENTS	47,063,469	48,840,860	(1,777,391)	48,840,860	27,732,720	19,210,565	345,192	1,045,337	507,046
20	**TOTAL RATE BASE**	**7,756,709,517**	**6,527,851,072**	**1,228,858,445**	**6,527,851,072**	**4,132,651,086**	**2,234,976,490**	**61,024,225**	**69,850,258**	**29,349,012**
21										
22	**DEVELOPMENT OF RETURN**									
23	BASE REVENUES FROM RATES	2,909,647,523	2,865,563,427	44,084,096	2,865,563,427	1,468,282,584	1,338,700,733	29,014,733	20,979,131	8,586,247
24	PROFORMA TO BASE REVENUES FROM RATES	20,828,962	20,828,962		20,828,962	16,802,725	4,245,725	(300,334)	90,653	(9,807)
25	SURCHARGE & OTHER ELECTRIC REVENUES	582,709,014	570,735,507	11,973,507	570,735,507	316,626,510	243,272,570	7,471,258	2,579,858	785,311
26	PROFORMA SURCHARGE & OTHER ELECTRIC REVENUES	(412,607,651)	(412,186,408)	(421,243)	(412,186,408)	(236,557,673)	(167,694,771)	(5,668,781)	(1,688,665)	(576,518)
27	**TOTAL OPERATING REVENUES**	**3,100,577,848**	**3,044,941,488**	**55,636,359**	**3,044,941,488**	**1,565,154,147**	**1,418,524,256**	**30,516,876**	**21,960,976**	**8,785,232**
28										
29	**OPERATING EXPENSES**									
30	OPERATION & MAINTENANCE	1,803,561,018	1,967,300,739	(163,739,721)	1,967,300,739	1,013,704,885	918,476,736	23,378,333	9,302,078	2,438,707
31	ADMINISTRATIVE & GENERAL	193,799,761	176,678,975	17,120,787	176,678,975	115,813,168	57,912,664	1,473,481	946,786	532,876
32	DEPRECIATION & AMORT EXPENSE	456,219,756	402,496,860	53,722,896	402,496,860	252,267,709	141,405,047	3,731,763	3,614,227	1,478,115
33	AMORTIZATION ON GAIN	(4,626,993)	(4,601,933)	(25,060)	(4,601,933)	(2,729,002)	(1,800,581)	(45,991)	(22,882)	(3,477)
34	REGULATORY ASSETS	17,910,882	17,910,882		17,910,882	10,643,995	6,985,797	178,603	88,967	13,519
35	PROFORMA ADJUSTMENTS	(104,494,426)	(108,548,777)	4,054,351	(108,548,777)	(43,943,824)	(62,043,061)	(2,243,480)	(215,365)	(103,047)
36	TAXES OTHER THAN INCOME	171,499,317	139,384,353	32,114,964	139,384,353	88,501,094	47,275,162	1,289,515	1,633,384	685,199
37	INCOME TAX	258,692,839	224,811,155	33,881,684	224,811,155	81,353,253	137,701,245	1,944,195	2,451,566	1,360,896
38	PROFORMA INCOME TAX ADJUSTMENTS	(111,768,188)	(109,837,407)	(1,930,782)	(109,837,407)	(67,776,045)	(39,869,471)	(1,439,155)	(554,581)	(198,155)
39	**TOTAL OPERATING EXPENSES**	**2,680,793,966**	**2,705,594,848**	**(24,800,882)**	**2,705,594,848**	**1,447,835,233**	**1,206,043,538**	**28,267,263**	**17,244,180**	**6,204,633**
40										
41	**OPERATING INCOME**	**419,783,882**	**339,346,640**	**80,437,242**	**339,346,640**	**117,318,914**	**212,480,718**	**2,249,613**	**4,716,796**	**2,580,599**
42										
43	**RATE OF RETURN (PRESENT)**	**5.41%**	**5.20%**	**6.55%**	**5.20%**	**2.84%**	**9.51%**	**3.69%**	**6.75%**	**8.79%**
44										
45	**INDEX RATE OF RETURN (PRESENT)**	**1.00**	**0.96**	**1.21**	**0.96**	**0.52**	**1.76**	**0.68**	**1.25**	**1.62**
46										
47	**DEVELOPMENT OF % OF COST OF SERVICE**									
48	Total Base Revenues	2,930,476,485	2,886,392,389	44,084,096	2,886,392,389	1,485,085,309	1,342,946,458	28,714,399	21,069,783	8,576,440
49	Surcharge Transfer to Base Rates	267,551,155	267,551,155		267,551,155	168,606,794	94,408,005	3,243,093	980,698	312,565
50	**Base Revenues, Including Surcharges (PRESENT)**	3,198,027,640	3,153,943,544	44,084,096	3,153,943,544	1,653,692,103	1,437,354,463	31,957,492	22,050,481	8,889,005
51										
52	**PROPOSED**									
53	Rate Increase by Class	254.00%	254.00%		254.00%	96.50%	120.28%	17.02%	10.10%	10.10%
54	**Base Revenue Increase @ Class Specific % (PROPOSED), Including Surcharges**	3,363,480,855	3,319,396,759	44,084,096	3,319,396,759	1,771,693,408	1,481,460,044	33,602,193	23,198,274	9,442,840
55										
56	REVENUE REQUIREMENT @ 7.48%	3,190,207,826	3,127,484,436	62,723,390	3,127,484,436	1,795,251,548	1,269,922,255	32,458,822	21,895,642	7,956,169
57	FAIR VALUE INCREMENT	25,925,245	25,925,245		25,925,245	16,534,930	8,748,708	240,275	281,759	119,574
58	**TOTAL REVENUE REQUIREMENT (INCLD FAIR VALUE INCREMENT)**	**3,216,133,071**	**3,153,409,681**	**62,723,390**	**3,153,409,681**	**1,811,786,478**	**1,278,670,963**	**32,699,097**	**22,177,401**	**8,075,743**
59										
60	**% OF TOTAL COST OF SERVICE**									
61	**% OF TOTAL COST OF SERVICE (PRESENT)**	**99.44%**	**100.02%**	**70.28%**	**100.02%**	**91.27%**	**112.41%**	**97.73%**	**99.43%**	**110.07%**
62										
63	**% OF TOTAL COST OF SERVICE (PROPOSED @ CLASS SPECIFIC %)**	**104.58%**	**105.26%**	**70.28%**	**105.26%**	**97.79%**	**115.86%**	**102.76%**	**104.60%**	**116.93%**

ARIZONA PUBLIC SERVICE COMPANY
ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING DECEMBER 31, 2015
($)

Return

Line #	2015 TY Cost of Service (Adjusted)	TOTAL GENERAL SVC	E-20 (Church Rate)	E-32 TOU (0-100 kW)	E-32 TOU (101-400 kW)	E-32 TOU (401+ kW)	School TOU	E-30, E-32 (0-100 kW)	E-32 (101-400 kW)	E-32 (401+ kW)	E-34	E-35
1												
2	**SUMMARY OF RESULTS**											
3												
4	**DEVELOPMENT OF RATE BASE**											
5	ELECTRIC PLANT IN SERVICE	4,554,642,478	35,879,010	11,427,670	20,584,527	64,756,490	58,758,131	1,699,623,772	1,072,049,524	921,309,172	211,511,618	458,742,564
6	GENERAL & INTANGIBLE PLANT	464,146,198	3,096,645	1,201,647	2,129,615	6,436,253	4,973,372	183,186,887	101,103,699	90,080,364	21,631,237	50,306,479
7	LESS: RESERVE FOR DEPRECIATION	(2,002,097,799)	(15,470,138)	(4,994,616)	(9,037,865)	(28,494,203)	(25,311,933)	(742,135,274)	(466,327,998)	(404,726,918)	(95,092,278)	(210,506,576)
8	OTHER DEFERRED CREDITS	(503,174,681)	(3,176,214)	(1,261,919)	(2,344,793)	(7,577,244)	(5,563,302)	(174,838,524)	(115,346,964)	(105,632,714)	(25,812,080)	(61,620,927)
9	WORKING CASH	(32,917,689)	(269,576)	(82,118)	(147,940)	(467,074)	(440,091)	(12,247,505)	(7,841,230)	(6,673,444)	(1,517,859)	(3,230,853)
10	MATERIALS, SUPPLIES & PREPAYMENTS	164,697,669	859,954	422,710	794,989	2,609,248	1,654,020	54,660,014	38,122,227	35,861,386	8,596,074	21,117,046
11	ACCUM. DEFERRED TAXES	(796,946,649)	(6,677,659)	(2,000,773)	(3,558,609)	(11,039,550)	(10,685,404)	(306,382,300)	(187,893,232)	(158,195,207)	(35,716,544)	(74,797,369)
12	REGULATORY ASSETS	63,623,483	545,521	171,513	275,748	714,988	743,620	31,108,115	12,939,718	10,319,839	2,289,123	4,515,297
13	DECOMMISSIONING FUND	285,200,677	2,188,437	687,285	1,281,536	4,183,938	3,652,953	98,600,144	67,083,645	59,438,957	14,638,660	33,445,123
15	MISCELLANEOUS DEFERRED DEBITS	40,082,726	238,784	103,947	187,843	582,662	406,307	15,032,013	8,824,866	8,076,128	1,950,371	4,679,805
16	OPEB	55,890,824	372,625	144,745	256,465	774,820	598,328	22,071,526	12,169,993	10,843,402	2,603,520	6,055,400
17	CUSTOMER ADVANCES	(44,764,989)	(141,280)	(139,627)	(228,624)	(697,879)	(375,081)	(17,171,511)	(10,472,745)	(9,088,278)	(1,911,601)	(4,538,363)
18	CUSTOMER DEPOSITS	(32,616,324)	(101,767)	(101,918)	(166,738)	(508,722)	(272,140)	(12,521,197)	(7,630,243)	(6,620,434)	(1,390,579)	(3,302,587)
19	PROFORMA ADJUSTMENTS	19,210,565	129,847	52,086	91,739	282,985	227,247	7,409,358	4,614,096	3,951,441	792,987	1,658,779
20	**TOTAL RATE BASE**	**2,234,976,490**	**17,474,187**	**5,630,633**	**10,117,894**	**31,556,712**	**28,366,027**	**846,395,520**	**521,395,357**	**448,943,694**	**102,572,648**	**222,523,819**
21												
22	**DEVELOPMENT OF RETURN**											
23	BASE REVENUES FROM RATES	1,338,700,733	4,176,910	4,183,101	6,843,561	20,879,912	11,169,689	513,918,578	313,174,826	271,728,356	57,074,785	135,551,017
24	PROFORMA TO BASE REVENUES FROM RATES	4,245,725	(115,162)	(18,184)	(73,642)	(348,818)	162,741	(2,760,103)	(4,762,531)	1,877,966	2,716,260	7,567,199
25	SURCHARGE & OTHER ELECTRIC REVENUES	243,272,570	1,080,040	794,726	1,184,024	3,141,198	2,347,068	103,074,992	57,784,217	42,240,994	9,760,280	21,865,031
26	PROFORMA SURCHARGE & OTHER ELECTRIC REVENUES	(167,694,771)	(831,475)	(600,842)	(802,479)	(1,875,640)	(1,753,226)	(80,163,049)	(40,247,364)	(24,894,779)	(5,549,408)	(10,976,510)
27	**TOTAL OPERATING REVENUES**	**1,418,524,256**	**4,310,312**	**4,358,800**	**7,151,463**	**21,796,652**	**11,926,272**	**534,070,418**	**325,949,148**	**290,952,537**	**64,001,917**	**154,006,737**
28												
29	**OPERATING EXPENSES**											
30	OPERATION & MAINTENANCE	918,476,736	3,528,067	2,344,263	4,272,726	13,880,507	7,777,510	294,711,543	203,691,065	206,747,597	50,026,538	131,496,921
31	ADMINISTRATIVE & GENERAL	57,912,664	391,904	150,079	265,032	797,201	624,691	23,054,380	12,594,649	11,172,043	2,675,339	6,187,346
32	DEPRECIATION & AMORT EXPENSE	141,405,047	1,048,365	357,655	644,381	2,018,088	1,727,203	52,921,068	32,711,099	28,530,249	6,641,891	14,805,049
33	AMORTIZATION ON GAIN	(1,800,581)	(13,687)	(4,345)	(8,107)	(26,488)	(22,922)	(621,071)	(423,373)	(375,914)	(92,580)	(212,093)
34	REGULATORY ASSETS	6,985,797	53,604	16,835	31,390	102,483	89,477	2,415,143	1,643,168	1,455,917	358,564	819,216
35	PROFORMA ADJUSTMENTS	(62,043,061)	(305,316)	(242,824)	(295,374)	(805,624)	(475,262)	(32,432,551)	(15,254,734)	(10,178,915)	(825,705)	(1,226,756)
36	TAXES OTHER THAN INCOME	47,275,162	382,023	119,764	213,183	661,837	618,446	18,112,874	11,137,510	9,440,218	2,116,235	4,473,071
37	INCOME TAX	137,701,245	(200,804)	711,305	907,308	2,239,353	786,232	79,002,121	37,289,990	17,868,106	1,066,297	(1,968,664)
38	PROFORMA INCOME TAX ADJUSTMENTS	(39,869,471)	(244,240)	(149,315)	(229,014)	(560,568)	(433,466)	(19,904,793)	(11,669,317)	(5,070,239)	(787,611)	(820,908)
39	**TOTAL OPERATING EXPENSES**	**1,206,043,538**	**4,639,917**	**3,303,417**	**5,801,524**	**18,306,790**	**10,691,909**	**417,258,713**	**271,720,058**	**259,589,061**	**61,178,968**	**153,553,181**
40												
41	**OPERATING INCOME**	**212,480,718**	**(329,605)**	**1,055,383**	**1,349,939**	**3,489,862**	**1,234,363**	**116,811,704**	**54,229,090**	**31,363,475**	**2,822,949**	**453,556**
42												
43	**RATE OF RETURN (PRESENT)**	**9.51%**	**(1.89%)**	**18.74%**	**13.34%**	**11.06%**	**4.35%**	**13.80%**	**10.40%**	**6.99%**	**2.75%**	**0.20%**
44												
45	**INDEX RATE OF RETURN (PRESENT)**	**1.76**	**(0.35)**	**3.46**	**2.47**	**2.04**	**0.80**	**2.55**	**1.92**	**1.29**	**0.51**	**0.04**
46												
47	**DEVELOPMENT OF % OF COST OF SERVICE**											
48	Total Base Revenues	1,342,946,458	4,061,747	4,164,917	6,769,919	20,531,094	11,332,430	511,158,475	308,412,295	273,606,322	59,791,045	143,118,215
49	Surcharge Transfer to Base Rates	94,408,005	460,711	333,161	482,565	1,097,227	1,059,278	43,875,354	23,704,724	13,847,374	3,185,587	6,362,024
50	**Base Revenues, Including Surcharges (PRESENT)**	1,437,354,463	4,522,458	4,498,078	7,252,484	21,628,321	12,391,708	555,033,829	332,117,019	287,453,695	62,976,632	149,480,239
51												
52	**PROPOSED**											
53	Rate Increase by Class	120.28%	20.36%	8.61%	11.68%	11.13%	15.38%	8.61%	11.68%	11.13%	10.84%	10.84%
54	**Base Revenue Increase @ Class Specific % (PROPOSED), Including Surcharges**	1,481,460,044	4,888,805	4,523,604	7,560,787	22,816,635	13,075,596	555,179,954	344,441,328	304,064,451	66,273,649	158,635,235
55												
56	REVENUE REQUIREMENT @ 7.48%	1,269,922,255	6,707,103	3,140,759	5,812,477	18,708,844	12,768,160	424,789,326	283,848,795	277,221,993	67,633,029	169,291,768
57	FAIR VALUE INCREMENT	8,748,708	70,471	21,998	39,362	122,172	113,172	3,348,855	2,042,546	1,744,133	396,804	849,195
58	**TOTAL REVENUE REQUIREMENT (INCLD FAIR VALUE INCREMENT)**	**1,278,670,963**	**6,777,574**	**3,162,758**	**5,851,839**	**18,831,015**	**12,881,331**	**428,138,181**	**285,891,341**	**278,966,126**	**68,029,833**	**170,140,964**
59												
60	**% OF TOTAL COST OF SERVICE**											
61	**% OF TOTAL COST OF SERVICE (PRESENT)**	**112.41%**	**66.73%**	**142.22%**	**123.94%**	**114.85%**	**96.20%**	**129.64%**	**116.17%**	**103.04%**	**92.57%**	**87.86%**
62												
63	**% OF TOTAL COST OF SERVICE (PROPOSED @ CLASS SPECIFIC %)**	**115.86%**	**72.13%**	**143.03%**	**129.20%**	**121.17%**	**101.51%**	**129.67%**	**120.48%**	**109.00%**	**97.42%**	**93.24%**

ARIZONA PUBLIC SERVICE COMPANY
ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING DECEMBER 31, 2015
($)

Return

Line #	2015 TY Cost of Service (Adjusted)	TOTAL RESIDENTIAL	RESIDENTIAL SOLAR (ENERGY RATES)	RESIDENTIAL SOLAR (DEMAND RATES)	RESIDENTIAL E-12	RESIDENTIAL ET-1 & ET-2	RESIDENTIAL ECT-1 & ECT-2
1							
2	**SUMMARY OF RESULTS**						
3							
4	**DEVELOPMENT OF RATE BASE**						
5	ELECTRIC PLANT IN SERVICE	8,099,051,086	359,317,931	18,729,906	2,181,586,792	3,967,361,127	1,572,055,331
6	GENERAL & INTANGIBLE PLANT	913,116,365	47,816,295	2,225,148	286,622,522	420,071,890	156,380,511
7	LESS: RESERVE FOR DEPRECIATION	(3,511,914,006)	(159,178,281)	(8,201,318)	(956,681,871)	(1,711,729,418)	(676,123,118)
8	OTHER DEFERRED CREDITS	(768,219,184)	(35,053,127)	(1,827,958)	(212,176,542)	(370,938,142)	(148,223,415)
9	WORKING CASH	(58,288,866)	(2,511,313)	(133,480)	(15,263,080)	(28,854,289)	(11,526,704)
10	MATERIALS, SUPPLIES & PREPAYMENTS	225,856,548	9,723,164	533,017	61,674,894	109,299,722	44,625,752
11	ACCUM. DEFERRED TAXES	(1,503,979,442)	(67,478,188)	(3,469,949)	(408,318,948)	(735,604,774)	(289,107,583)
12	REGULATORY ASSETS	181,817,468	10,423,768	446,656	61,820,875	80,998,943	28,127,225
13	DECOMMISSIONING FUND	434,549,532	18,565,663	1,012,884	108,810,613	217,388,521	88,771,851
15	MISCELLANEOUS DEFERRED DEBITS	71,286,870	3,631,865	173,502	22,038,643	32,952,466	12,490,395
16	OPEB	110,070,359	5,767,796	268,270	34,575,849	50,620,945	18,837,500
17	CUSTOMER ADVANCES	(49,850,247)	(679,199)	(76,618)	(15,137,036)	(24,414,448)	(9,542,946)
18	CUSTOMER DEPOSITS	(38,578,117)	(513,370)	(58,959)	(11,736,666)	(18,889,435)	(7,379,687)
19	PROFORMA ADJUSTMENTS	27,732,720	1,211,190	61,173	7,874,183	13,453,529	5,132,645
20	**TOTAL RATE BASE**	**4,132,651,086**	**191,044,193**	**9,682,274**	**1,145,690,229**	**2,001,716,634**	**784,517,756**
21							
22	**DEVELOPMENT OF RETURN**						
23	BASE REVENUES FROM RATES	1,468,282,584	19,538,868	2,243,969	446,697,353	718,931,632	280,870,762
24	PROFORMA TO BASE REVENUES FROM RATES	16,802,725	3,128,392	119,286	8,053,164	5,161,952	339,931
25	SURCHARGE & OTHER ELECTRIC REVENUES	316,626,510	7,335,405	520,527	95,962,097	152,180,429	60,628,053
26	PROFORMA SURCHARGE & OTHER ELECTRIC REVENUES	(236,557,673)	(4,087,358)	(327,941)	(74,221,765)	(113,653,421)	(44,267,189)
27	**TOTAL OPERATING REVENUES**	**1,565,154,147**	**25,915,307**	**2,555,841**	**476,490,849**	**762,620,592**	**297,571,557**
28							
29	**OPERATING EXPENSES**						
30	OPERATION & MAINTENANCE	1,013,704,885	21,828,096	1,464,598	289,569,423	493,896,198	206,946,571
31	ADMINISTRATIVE & GENERAL	115,813,168	6,086,865	282,200	36,459,360	53,226,590	19,758,152
32	DEPRECIATION & AMORT EXPENSE	252,267,709	11,640,073	591,459	70,592,332	121,750,702	47,693,143
33	AMORTIZATION ON GAIN	(2,729,002)	(116,504)	(6,363)	(683,914)	(1,364,650)	(557,570)
34	REGULATORY ASSETS	10,643,995	454,753	24,810	2,665,242	5,324,784	2,174,406
35	PROFORMA ADJUSTMENTS	(43,943,824)	20,354	(15,146)	(16,393,681)	(20,593,087)	(6,962,265)
36	TAXES OTHER THAN INCOME	88,501,094	3,966,033	204,165	24,214,339	43,159,527	16,957,029
37	INCOME TAX	81,353,253	(8,113,111)	(5,628)	35,819,427	41,904,414	11,748,151
38	PROFORMA INCOME TAX ADJUSTMENTS	(67,776,045)	(263,103)	(71,536)	(19,298,859)	(33,917,746)	(14,224,800)
39	**TOTAL OPERATING EXPENSES**	**1,447,835,233**	**35,503,458**	**2,468,558**	**422,943,668**	**703,386,732**	**283,532,817**
40							
41	**OPERATING INCOME**	**117,318,914**	**(9,588,151)**	**87,283**	**53,547,181**	**59,233,861**	**14,038,740**
42							
43	**RATE OF RETURN (PRESENT)**	**2.84%**	**(5.02%)**	**0.90%**	**4.67%**	**2.96%**	**1.79%**
44							
45	**INDEX RATE OF RETURN (PRESENT)**	**0.52**	**(0.93)**	**0.17**	**0.86**	**0.55**	**0.33**
46							
47	**DEVELOPMENT OF % OF COST OF SERVICE**						
48	Total Base Revenues	1,485,085,309	22,667,260	2,363,255	454,750,517	724,093,584	281,210,693
49	Surcharge Transfer to Base Rates	168,606,794	2,647,624	239,511	51,043,792	81,795,704	32,880,163
50	**Base Revenues, Including Surcharges (PRESENT)**	1,653,692,103	25,314,884	2,602,766	505,794,309	805,889,288	314,090,856
51							
52	**PROPOSED**						
53	Rate Increase by Class	96.50%	19.30%	19.30%	19.30%	19.30%	19.30%
54	**Base Revenue Increase @ Class Specific % (PROPOSED), Including Surcharges**	1,771,693,408	27,041,837	2,819,342	542,513,274	863,837,129	335,481,826
55							
56	REVENUE REQUIREMENT @ 7.48%	1,795,251,548	61,256,948	3,392,972	506,774,730	870,436,618	353,390,280
57	FAIR VALUE INCREMENT	16,534,930	767,156	38,710	4,585,684	8,011,421	3,131,960
58	**TOTAL REVENUE REQUIREMENT (INCLD FAIR VALUE INCREMENT)**	**1,811,786,478**	**62,024,104**	**3,431,682**	**511,360,414**	**878,448,039**	**356,522,239**
59							
60	**% OF TOTAL COST OF SERVICE**						
61	**% OF TOTAL COST OF SERVICE (PRESENT)**	**91.27%**	**40.81%**	**75.85%**	**98.91%**	**91.74%**	**88.10%**
62							
63	**% OF TOTAL COST OF SERVICE (PROPOSED @ CLASS SPECIFIC %)**	**97.79%**	**43.60%**	**82.16%**	**106.09%**	**98.34%**	**94.10%**

Arizona Public Service Company
Test Year Ending December 31, 2015
Staff Revenue Allocation

Attachment RCS-12
Docket No. E-01345A-16-0036
Page 1 of 1

Line No.	Description	Total ACC Retail (A)	Residential (B)	General Service (C)	E-221 (Water Pumping) (D)	Street Lighting (E)	Dusk to Dawn (F)
	I. Per APS						
1	Base Revenues, including Surcharges (PRESENT) Per APS	$ 2,888,903,571	$ 1,486,577,643	$ 1,343,925,896	$ 28,739,440	$ 21,082,257	$ 8,578,335
2	Percent of Total Retail Base Rate Revenues	100.00%	51.46%	46.52%	0.99%	0.73%	0.30%
	From Cost of Service Study						
3	Base Revenue Increase @ Class Specific % (PROPOSED), including Surcharges Per APS	$ 3,322,304,142	$ 1,773,473,749	$ 1,482,541,961	$ 33,631,497	$ 23,212,008	$ 9,444,927
4	Percent of Total Retail Revenue Requirement Per APS	100.00%	53.38%	44.62%	1.01%	0.70%	0.28%
5	Dollar Increase per APS	$ 433,400,571	$ 286,896,106	$ 138,616,065	$ 4,892,057	$ 2,129,751	$ 866,592
6	Percent Increase Per APS	15.00%	19.30%	10.31%	17.02%	10.10%	10.10%
	From Proof of Revenue (H-1)						
7	Base Revenue Increase @ Class Specific % (PROPOSED), including Surcharges Per APS	$ 3,322,337,000	$ 1,773,473,000	$ 1,482,576,000	$ 33,631,000	$ 23,212,000	$ 9,445,000
8	Percent of Total Retail Revenue Requirement Per APS	100.00%	53.38%	44.62%	1.01%	0.70%	0.28%
9	Dollar Increase per APS	$ 433,433,429	$ 286,895,357	$ 138,650,104	$ 4,891,560	$ 2,129,743	$ 866,665
10	Percent Increase Per APS	15.00%	19.30%	10.32%	17.02%	10.10%	10.10%
	II. Per Staff						
11	Base Revenues at present rates, including Surcharges (PRESENT) Per Staff	$ 2,886,392,389	$ 1,485,085,309	$ 1,342,946,458	$ 28,714,399	$ 21,069,783	$ 8,576,440
12	Percent of Total Retail Base Rate Revenues	100.00%	51.45%	46.53%	0.99%	0.73%	0.30%
13	Index Rate of Return (Present) From Staff COSS Run	0.96	0.52	1.76	0.68	1.25	1.62
14	Restated to Jurisdictional Revenue Requirement = 1.00	1.00	0.55	1.83	0.71	1.30	1.69
	From Cost of Service Study (Used to Develop Rates)						
15	Total proposed Revenue Requirement (Including Fair Value Increment) Per Staff	$ 3,153,943,544	$ 1,653,692,103	$ 1,437,354,463	$ 31,957,492	$ 22,050,481	$ 8,889,005
16	Percent of Total Retail Revenue Requirement Per Staff	100.00%	52.43%	45.57%	1.01%	0.70%	0.28%
17	Dollar Increase per Staff	$ 265,039,973	$ 167,114,460	$ 93,428,567	$ 3,218,052	$ 968,224	$ 310,670
18	Percent Increase Per Staff	9.17%	11.24%	6.95%	11.20%	4.59%	3.62%
19	Index Rate of Return (Present) From Staff COSS Run (Proposed Rates)	1.0526	0.9779	1.1586	1.0276	1.046	1.1693
20	Restated to Jurisdictional Revenue Requirement = 1.00	1.00	0.93	1.10	0.98	0.99	1.11
	Equal Percentage Increase (Across the Board by Revenue) (Not Used -Informational Only)						
21	Dollar Increase per Staff	$ 265,039,973	$ 136,384,787	$ 123,297,325	$ 2,636,675	$ 1,934,174	$ 787,012
22	Percent Increase Per Staff	9.17%	9.17%	9.17%	9.17%	9.17%	9.17%
23	Total Revenue Requirement (Including Fair Value Increment) Per Staff	$ 3,153,943,544	$ 1,622,962,430	$ 1,467,223,221	$ 31,376,115	$ 23,016,431	$ 9,365,347
24	Percent of Total Retail Revenue Requirement Per Staff	100.00%	51.46%	46.52%	0.99%	0.73%	0.30%

Notes and Source
Part I: From APS's Class Cost of Service Study (LRS_WP04DR) and APS Exhibit H-1, Proof of Revenues
Part II: Amounts from Staff Class Cost of Service Study (Exhibit RCS-11)

Arizona Public Service Company
Staff Proof of Revenues

Test Year Ended December 31, 2015

Line No.	Customer Classification	APS Present Rates ($000) (A)	Staff Proposed Rates ($000) (B)	Change ($000) (C) = (B) - (A)	Allocation of Rate Increase (D)	Change from Present Rates % (E) = (C) / (A)	Adjustor Transfers 3 ($000) (F)	Net Change ($000) (G) = (C) - (F)	Net Increase 4 % (H) = (G) / (A)
1	Residential	$ 1,486,578	$ 1,653,692	$ 167,114	63.05%	11.24%	$ 168,607	$ (1,493)	-0.10%
2	General Service	$ 1,343,926	$ 1,437,362	$ 93,436	35.25%	6.95%	$ 94,409	$ (973)	-0.07%
3	Irrigation/Water Pumping	$ 28,739	$ 31,957	$ 3,218	1.21%	11.20%	$ 3,243	$ (25)	-0.09%
4	Outdoor Lighting	$ 21,082	$ 22,050	$ 968	0.37%	4.59%	$ 979	$ (11)	-0.05%
5	Dusk to Dawn Lighting Service	$ 8,578	$ 8,889	$ 311	0.12%	3.63%	$ 313	$ (2)	-0.02%
6	Total Sales to Ultimate Retail Customers	$ 2,888,903	$ 3,153,950	$ 265,047	100.00%	9.17%	$ 267,551	$ (2,504)	-0.09%
7	Total Rev Req Including Revenue Adjustors		$ 3,153,869						
8	Difference (Rounding)		$ 81 *						

Notes and Source

Line No.		$000's			
9	Staff Revenue Deficiency (Sch. A, line 9	$ 267,477		Line 6 Above	$ (2,503,585)
10	Staff Revenues from Base Rates (Sch. A, line 12	$ 2,886,392		Red Rock Rev	$ (2,511,183)
11	Total Rev Req Including Revenue Adjustors	$ 3,153,869		Difference	$ 7,598 *
12	Staff Revenue Deficiency (Sch. A, line 9	$ 267,477			
13	Less Revenue Adjustors	$ (267,551)			
14	Net Customer Bill Impact of Requested Increase	$ (74)			

* This difference results from rounding differences between APS's Cost of Service Study and Proof of Revenue for certain rate classes within General Services

Arizona Public Service Company
Staff Proof of Revenues - Present and Proposed Revenues
Test Year Ended December 31, 2015

Attachment RCS-13
Docket No. E-01345A-16-0036

Rate Class	Billed	Unbilled	Total Before Adjustments	Test Year True-up	Weather Proforma	Customer Proforma	Solar Contract Limited Inc Proforma	AG-1 cancel Proforma	Total Adjusted Per APS	Staff Proposed Revenue Increase	Adjusted Proposed Revenue Per Staff
E-12	444,944,930	881,164	445,826,094	871,259	7,424,361	2,201,400	(1,198,920)		455,124,194	11.13%	505,794,308
ET-1	235,938,170	456,519	236,394,689	9,885	2,555,134	85,266	(665,849)		238,379,125	11.18%	265,033,864
ET-2	478,569,249	122,546	478,691,795	809,788	5,073,110	170,190	(1,343,213)		483,401,670	11.18%	537,453,992
ECT-2	212,833,575	693,768	213,527,343	(60,914)	1,024,332	126,425	(677,084)		213,940,102	11.57%	238,695,975
ECT-1R	67,035,738	378,624	67,414,362	(10,030)	343,069	40,549	(212,498)		67,575,452	11.57%	75,394,881
ET-SP	2,477,883	18,544	2,496,427	2,695	26,897	907	-		2,526,926	11.18%	2,809,478
ET-EV	528,276	(1,509)	526,767	(415)	5,875	192	-		532,419	11.18%	591,952
E-12 Solar Legacy	4,600,481	(145,314)	4,455,167	(29,133)	235,686	550,376	(28,776)		5,183,320	11.37%	5,772,515
ET-1 Solar Legacy	3,994,004	(95,595)	3,898,409	(1,955)	114,573	549,925	(34,852)		4,526,100	11.37%	5,040,588
ET-2 Solar Legacy	11,514,262	(289,556)	11,224,706	(8,327)	320,809	1,583,141	(98,730)		13,021,599	11.37%	14,501,782
ECT-2 Solar Legacy	1,453,539	(6,085)	1,447,454	75,371	16,386	73,852	(7,072)		1,605,991	9.97%	1,766,155
ECT-1R Solar Legacy	687,512	(959)	686,553	34,591	7,937	35,038	(3,377)		760,742	9.97%	836,610
E-20	4,158,297	(14,423)	4,143,874	33,036	(85,112)	(13,745)	(8,789)		4,069,264	11.14%	4,522,459
E-30	1,139,213	2,245	1,141,458	55,777	-	10,375	(1,703)		1,205,907	8.51%	1,308,549
E-32 XS	211,741,196	(64,771)	211,676,425	(165,441)	(1,502,039)	844,420	(505,943)		210,347,422	8.51%	228,251,417
E-32 XS Solar Legacy	803,227	-	803,227	-	-	-	(1,475)		801,752	8.51%	869,994
E-32 S	300,550,784	(417,524)	300,133,260	230,814	(1,389,067)	1,001,639	(877,695)		299,098,951	8.51%	324,557,148
E-32 M	311,463,665	(236,053)	311,227,612	(1,047,937)	(2,228,791)	(1,631,993)	(1,128,368)		305,190,523	7.61%	328,402,309
E-32 L	242,284,089	(251,547)	242,032,542	(952,864)	(1,046,942)	384,518	(1,177,238)		239,240,016	4.98%	251,160,711
E-32TOU XS	799,341	(925)	798,416	(4,618)	(4,880)	4,803	(2,121)		791,600	7.94%	854,438
E-32TOU S	3,402,876	(971)	3,401,905	(12,603)	(14,209)	11,634	(11,052)		3,375,675	7.94%	3,643,638
E-32TOU M	6,822,276	(14,472)	6,807,804	35,757	(43,299)	-	(25,942)		6,774,320	7.06%	7,252,484
E-32TOU L	20,853,748	(18,055)	20,835,693	44,218	(57,524)	(352,033)	(88,893)		20,381,461	5.27%	21,455,676
E-34	49,759,581	(19,171)	49,740,410	(65,027)	-	1,083,222	(289,798)		50,468,807	5.24%	53,113,061
E-35	96,030,508	(79,855)	95,950,653	144,886	-	2,066,275	(658,941)		97,502,873	4.36%	101,755,499
E-36 M (XS & S)*			42,005	1,053					43,058	8.51%	46,723
E-36 M (L)*			766,906	19,223					786,129	4.98%	825,300
E-36 M									829,187		
E-221	28,988,401	41,789	29,030,190	(15,457)	-	(158,913)	(116,380)		28,739,440	11.20%	31,957,491
GS-S M	5,387,423	(21,463)	5,365,960	30,465	(36,022)	75,056	(14,009)		5,421,450	9.23%	5,921,655
GS-S L	5,840,788	(28,194)	5,812,594	(39,330)	(46,494)	214,426	(17,671)		5,923,525	9.23%	6,470,053
E-47	8,459,954	19,476	8,479,430	106,817	-	-	(7,912)		8,578,335	3.62%	8,889,005
E-58	8,757,290	(465)	8,756,825	356,788	-	65,041	(9,591)		9,169,063	4.59%	9,590,162
E-59	10,420,592	3,114	10,423,706	(300,475)	-	77,134	(34,052)		10,166,313	4.59%	10,633,211
E-67, OPA	503,494	(1)	503,493	(741)	-	3,730	(3,331)		503,151	4.59%	526,259
Contract 12	1,240,881	(86)	1,240,795	(1,561)	-	9,038	(4,840)		1,243,432	4.59%	1,300,538
E-32M AG-1	1,208,122	-	1,208,122	13,213	(30,312)	(22,161)	-	2,465,299	3,634,161	7.61%	3,910,563
E-32L AG-1	11,925,015	-	11,925,015	202,424	(149,219)	54,964	-	20,904,513	32,937,697	4.98%	34,578,895
E-32LTOU AG-1	231,417	-	231,417	(15)	(508)	(4,010)	-	600,192	827,076	5.27%	870,667
E-34 AG-1	2,953,551	-	2,953,551	89,037	-	189,108	-	6,141,115	9,372,811	5.24%	9,863,887
E-35 AG-1	5,666,339	-	5,666,339	30,108	-	655,163	-	22,604,376	28,955,986	4.36%	30,218,912
XHLF	16,643,579	(76,213)	16,567,366	(1)	-	341,261	(132,702)		16,775,924	4.36%	17,507,612
Total	2,822,613,266	834,582	2,824,256,759	480,360	10,513,751	10,326,213	(9,388,817)	52,715,495	2,889,732,949		3,153,950,415
										Staff Rev Req	3,153,869,174
										Difference	81,241
										Percentage Difference	0.0026%

* APS advised that the E-36 M rate classification is split between "XS&S" and "L" (calculated below) and allocated between the above rate classes

E-36 M (XS & S)	43,058	5.19%
E-36 M (L)	786,129	94.81%
Total E-36 M Rider	829,187	100.00%

Residential
General Service
Irrigation
Dusk to Dawn Lighting
Outdoor Lighting

ARIZONA PUBLIC SERVICE COMPANY
General Service Rate E-32 XS
Test Year Ending Dec-15
Proof of Revenue

Charge	Present Units	Present Rate ($)	Present Revenue ($)	Proposed Units	Staff Proposed Revenue Increase	Staff Proposed Rate ($)	Staff Proposed Revenue
	(A)	(B)	(C)		(D)	(E)	(F)
Summer Days							
Self contained Meter	16,557,169	0.672	11,126,418	16,557,169		0.986	16,330,358
Instrument rated meter	1,346,580	1.324	1,782,872	1,346,580		1.943	2,616,423
Primary Meter	5,551	3.415	18,957	5,551		5.014	27,831
kW Secondary	-		-				
kW Primary	-		-				
kWh secondary tier 1	740,107,743	0.13537	100,188,385	782,622,282		0.13685	107,102,093
kWh secondary tier 2	42,514,539	0.07427	3,157,555			-	
kWh primary tier 1	381,789	0.13209	50,431	484,231		0.12350	59,801
kWh primary tier 2	102,442	0.07100	7,273			-	
Billed kWh, Revenue	783,106,513		116,331,891	783,106,513			126,136,507
Winter Days							
Self contained Meter	16,872,816	0.672	11,338,532	16,872,816		0.986	16,641,682
Instrument rated meter	1,681,581	1.324	2,226,413	1,681,581		1.943	3,267,335
Primary Meter	5,455	3.415	18,629	5,455		5.014	27,350
kW Secondary	-		-				
kW Primary	-		-				
kWh secondary tier 1	678,762,939	0.11769	79,883,610	712,229,022		0.11767	83,807,106
kWh secondary tier 2	33,466,083	0.05658	1,893,511			-	
kWh primary tier 1	352,433	0.11438	40,311	431,270		0.10556	45,527
kWh primary tier 2	78,837	0.05329	4,201	-		-	
Billed kWh, Revenue	712,660,292		95,405,207	712,660,292			103,788,999
Riders - Summer	SGSP		2,049				2,544
Riders - Winter	SGSP		2,049				2,511
Subtotal	-		4,098				5,055
Total Billed Revenue	kWh		Revenue				
Summer	783,106,513		116,333,940	783,106,513	8.43%		126,139,051
Winter	712,660,292		95,407,256	712,660,292	8.79%		103,791,510
Annual	1,495,766,805		211,741,196	1,495,766,805			229,930,561
Unbilled kWh, Revenue	-		(64,771)				(79,367)
Total Before Adjustments	kWh		Revenue				
Summer	783,106,513		116,333,940	783,106,513	8.43%		126,139,051
Winter	712,660,292		95,342,485	712,660,292	8.78%		103,712,143
Annual	1,495,766,805		211,676,425	1,495,766,805			229,851,194
Test Year Actual Billed Revenue			211,575,755				
Reconcilliation to Test Year			(165,441)				
Summer			(90,896)				(90,896)
Winter			(74,545)				(74,545)
Weather Adustment	kWh	$-kWh	Revenue				
Summer	(5,043,000)	0.13204	(665,878)	(5,043,000)			(826,735)
Winter	(7,283,000)	0.11481	(836,161)	(7,283,000)			(1,024,585)
Annual	(12,326,000)		(1,502,039)	(12,326,000)			(1,851,319)
		input from rebill					
Customer Adjustment	kWh	$-kWh	Revenue				
Summer	2,709,000	0.14856	402,449	2,709,000			499,669
Winter	3,301,000	0.13389	441,971	3,301,000			541,566
Annual	6,010,000		844,420	6,010,000			1,041,235
Limited Income, AG-1 Adjustments			Revenue				
Summer			(264,886)				(328,875)
Winter			(241,057)				(295,378)
Annual			(505,943)				(624,252)
Total Adjustments	kWh		Revenue				
Summer	(2,334,000)		(619,211)	(2,334,000)			(746,837)
Winter	(3,982,000)		(709,792)	(3,982,000)			(852,941)
Annual	(6,316,000)		(1,329,003)	(6,316,000)			(1,599,778)
Adjusted Revenue	kWh		Revenue				
Summer	780,772,513		115,714,729	780,772,513	8.36%		125,392,214
Winter	708,678,292		94,632,693	708,678,292	8.69%		102,859,203
Annual	1,489,450,805		210,347,422	1,489,450,805	8.51%		228,251,417

Notes and Source

	210,347,422	Revenue Needed:	Total	228,251,417
Percentage Increase Over Current Base Rates	8.51%		Fixed	38,910,979
	100.00%		Other	189,340,438
Application of Base Rate Increase to this Rate	8.51%			

	Present		Staff Proposed
Self contained Meter (Monthly)	$ 20.44	(Daily Rate x 365/12)	$ 30.00
Instrument rated meter (Monthly)	$ 40.27	(Daily Rate x 365/12)	$ 59.10
Primary Meter (Monthly)	$ 103.87	(Daily Rate x 365/12)	$ 152.50

ARIZONA PUBLIC SERVICE COMPANY
General Service Rate E-32 TOU XS
Test Year Ending Dec-15

Charge	Present Units	Present Rate ($)	Present Revenue ($)	Proposed Units	Staff Proposed Revenue Increase	Staff Proposed Rate ($)	Staff Proposed Revenue
	(A)	(B)	(C)		(D)	(E)	(F)
Summer Days							
Self contained Meter	39,507	0.710	28,050	39,507	11.13%	0.789	31,173
Instrument rated meter	5,753	1.324	7,617	5,753	24.16%	1.644	9,457
Primary Meter	-	3.415	-				
kW Secondary - on	-	-	-				
kW Secondary - off	-	-	-				
kW Primary - on							
kW Primary - off							
kWh tier 1 - secondary - on	1,029,226	0.17033	175,308	373,726		0.22278	83,259
kWh tier 2 - secondary - on	-	0.08564	-				
kWh tier 1 - secondary - off	1,558,884	0.12686	197,760	2,478,317		0.13243	328,202
kWh tier 2 - secondary - off	263,933	0.04755	12,550			-	
kWh tier 1 - primary - on	-	0.16698	-				
kWh tier 2 - primary - on	-	0.08150	-				
kWh tier 1 - primary - off	-	0.12350	-				
kWh tier 2 - primary - off	-	0.04420	-				
Billed kWh, Revenue	2,852,043		421,285	2,852,043	7.31%		452,091
Winter Days							
Self contained Meter	39,420	0.710	27,988	39,420	11.13%	0.789	31,104
Instrument rated meter	7,709	1.324	10,207	7,709	24.15%	1.644	12,672
Primary Meter	-	3.415	-				
kW Secondary - on	-	-	-				
kW Secondary - off	-	-	-				
kW Primary - on							
kW Primary - off							
kWh tier 1 - secondary - on	979,577	0.15310	149,973	394,916		0.19205	75,842
kWh tier 2 - secondary - on	-	0.06837	-				
kWh tier 1 - secondary - off	1,551,769	0.10959	170,058	2,703,651		0.10751	290,673
kWh tier 2 - secondary - off	567,221	0.03496	19,830			-	
kWh tier 1 - primary - on	-	0.14974	-				
kWh tier 2 - primary - on	-	0.06423	-				
kWh tier 1 - primary - off	-	0.10624	-				
kWh tier 2 - primary - off	-	0.03160	-				
Billed kWh, Revenue	3,098,567		378,056	3,098,567	8.53%		410,291
Riders - Summer	-		-				
Riders - Winter	-		-				
Subtotal	-		-				
Total Billed Revenue	kWh		Revenue				
Summer	2,852,043		421,285	2,852,043	7.31%		452,091
Winter	3,098,567		378,056	3,098,567	8.53%		410,291
Annual	5,950,610		799,341	5,950,610			862,383
Unbilled kWh, Revenue	(6,909)		(925)	(6,909)	6.48%		(985)
Total Before Adjustments	kWh		Revenue	kWh			
Summer	2,852,043		421,285	2,852,043	7.31%		452,091
Winter	3,091,658		377,131	3,091,658	8.53%		409,306
Annual	5,943,701		798,416	5,943,701			861,398
Test Year Actual Billed Revenue			794,723				
Reconcilliation to Test Year			(4,618)				
Summer			(2,434)				(2,434)
Winter			(2,184)				(2,184)
Weather Adustment	kWh	$-kWh	Revenue			$-kWh	
Summer	(15,000)	0.13521	(2,028)	(15,000)	6.70%	0.14426	(2,164)
Winter	(26,000)	0.10968	(2,852)	(26,000)	6.48%	0.11680	(3,037)
Annual	(41,000)		(4,880)	(41,000)			(5,201)
Customer Adjustment	kWh	$-kWh	Revenue			$-kWh	
Summer	16,000	0.14771	2,363	16,000	6.70%	0.15759	2,521
Winter	20,000	0.12201	2,440	20,000	6.48%	0.12991	2,598
Annual	36,000		4,803	36,000			5,120
Limited Income, AG-1 Adjustments			Revenue				
Summer			(1,018)		6.70%		(1,086)
Winter			(1,103)		6.48%		(1,175)
Annual			(2,121)				(2,261)
Total Adjustments	kWh		Revenue				
Summer	1,000		(3,117)	1,000			(3,163)
Winter	(6,000)		(3,699)	(6,000)			(3,797)
Annual	(5,000)		(6,816)	(5,000)			(6,960)
Adjusted Revenue	kWh		Revenue				
Summer	2,853,043		418,168	2,853,043	7.36%		448,928
Winter	3,085,658		373,432	3,085,658	8.59%		405,509
Annual	5,938,701		791,600	5,938,701	7.94%		854,438

Notes and Source

Percentage Increase Over Current Base Rates	7.94%	Revenue Needed:	Total	$ 854,438
Portion of Components of this Rate to which Base Rate is being Applied	100.00%		Fixed	$ 84,406
Application of Base Rate Increase to this Rate	7.94%		Other	$ 770,032

	Present		Staff Proposed
Self contained Meter - Monthly	$ 21.60	(Daily Rate x 365/12)	$ 24.00
Instrument rated meter - Monthly	$ 40.27	(Daily Rate x 365/12)	$ 50.00

	Per APS						Per Staff		
Charge	Present Units	Present Rate ($)	Present Revenue ($)	Proposed Units	Proposed Rate ($)	Proposed Revenue ($)	Proposed Units	Proposed Rate ($)	Proposed Revenue ($)
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Summer Days				w/o transfer			w/o transfer		
Self contained Meter	16,557,169	0.672	11,126,418	16,557,169	1.160	19,206,316	16,557,169	0.658	10,886,906
Instrument rated meter	1,346,580	1.324	1,782,872	1,346,580	2.020	2,720,092	1,346,580	1.315	1,770,845
Primary Meter	5,551	3.415	18,957	5,551	4.947	27,461	5,551	3.288	18,250
kW Secondary	-		-	2,959,792	6.900	20,422,565	2,959,792	6.900	20,422,565
kW Primary	-		-	1,125	4.300	4,838	1,125	4.300	4,838
kWh secondary tier 1	740,107,743	0.13537	100,188,385	782,622,282	0.10549	82,554,911	782,622,282	0.11921	93,299,751
kWh secondary tier 2	42,514,539	0.07427	3,157,555						
kWh primary tier 1	381,789	0.13209	50,431	484,231	0.09951	48,186	484,231	0.11246	54,457
kWh primary tier 2	102,442	0.07100	7,273	-			-		
Billed kWh, Revenue	783,106,513		116,331,891	783,106,513		124,984,369	783,106,513		126,457,612
Winter Days				w/o transfer			w/o transfer		
Self contained Meter	16,872,816	0.672	11,338,532	16,872,816	1.160	19,572,467	16,872,816	0.658	11,094,454
Instrument rated meter	1,681,581	1.324	2,226,413	1,681,581	2.020	3,396,794	1,681,581	1.315	2,211,394
Primary Meter	5,455	3.415	18,629	5,455	4.947	26,986	5,455	3.288	17,934
kW Secondary	-		-	2,971,832	6.900	20,505,641	2,971,832	6.900	20,505,641
kW Primary	-		-	1,447	4.300	6,222	1,447	4.300	6,222
kWh secondary tier 1	678,762,939	0.11769	79,883,610	712,229,022	0.08630	61,465,365	712,229,022	0.09753	69,465,319
kWh secondary tier 2	33,466,083	0.05658	1,893,511						
kWh primary tier 1	352,433	0.11438	40,311	431,270	0.08050	34,717	431,270	0.09098	39,236
kWh primary tier 2	78,837	0.05329	4,201	-			-		
Billed kWh, Revenue	712,660,292		95,405,207	712,660,292		105,008,192	712,660,292		103,340,200
Riders - Summer	SGSP		2,049	SGSP		2,049	SGSP	-	2,049
Riders - Winter	SGSP		2,049	SGSP		2,049	SGSP		2,049
				Impact of annual placement		(131,755)	Annual placement		-
Subtotal	-		4,098	-		(127,657)	-		4,098
Total Billed Revenue	kWh		Revenue	kWh		Revenue	kWh		Revenue
Summer	783,106,513		116,333,940	783,106,513		124,986,418	783,106,513		126,459,661
Winter	712,660,292		95,407,256	712,660,292		104,878,486	712,660,292		103,342,249
Annual	1,495,766,805		211,741,196	1,495,766,805		229,864,904	1,495,766,805		229,801,910
Unbilled kWh, Revenue	-		(64,771)	-		(70,158)	-		(70,158)
Total Before Adjustments	kWh		Revenue	kWh		Revenue	kWh		Revenue
Summer	783,106,513		116,333,940	783,106,513		124,986,418	783,106,513		126,459,661
Winter	712,660,292		95,342,485	712,660,292		104,808,328	712,660,292		103,272,091
Annual	1,495,766,805		211,676,425	1,495,766,805		229,794,746	1,495,766,805		229,731,752
Test Year Actual Billed Revenue			211,575,755						
Reconcilliation to Test Year			(165,441)			(179,602)			
Summer			(90,896)			(97,657)			(97,657)
Winter			(74,545)			(81,945)			(81,945)
Weather Adustment	kWh	$-kWh	Revenue	kWh	$-kWh	Revenue	kWh	$-kWh	Revenue
Summer	(5,043,000)	0.13204	(665,878)	(5,043,000)	0.10548	(531,936)	(5,043,000)	0.11921	(601,169)
Winter	(7,283,000)	0.11481	(836,161)	(7,283,000)	0.08630	(628,523)	(7,283,000)	0.09753	(710,328)
Annual	(12,326,000)		(1,502,039)	(12,326,000)		(1,160,459)	(12,326,000)		(1,311,497)
		input from rebill							
Customer Adjustment	kWh	$-kWh	Revenue	kWh	$-kWh	Revenue	kWh	$-kWh	Revenue
Summer	2,709,000	0.14856	402,449	2,709,000	0.15960	432,356	2,709,000	0.18037	488,629
Winter	3,301,000	0.13389	441,971	3,301,000	0.14716	485,775	3,301,000	0.16631	549,001
Annual	6,010,000		844,420	6,010,000		918,131	6,010,000		1,037,630
Limited Income, AG-1 Adjustments			Revenue			Revenue			Revenue
Summer			(264,886)			(475,700)			(537,614)
Winter			(241,057)			(432,907)			(489,252)
Annual			(505,943)			(908,607)			(908,607)
Total Adjustments	kWh		Revenue	kWh		Revenue	kWh		Revenue
Summer	(2,334,000)		(619,211)	(2,334,000)		(672,937)	(2,334,000)		(747,811)
Winter	(3,982,000)		(709,792)	(3,982,000)		(657,600)	(3,982,000)		(732,524)
Annual	(6,316,000)		(1,329,003)	(6,316,000)		(1,330,537)	(6,316,000)		(1,480,335)
Adjusted Revenue	kWh		Revenue	kWh		Revenue	kWh		Revenue
Summer	780,772,513		115,714,729	780,772,513		124,313,481	780,772,513		125,711,850
Winter	708,678,292		94,632,693	708,678,292		104,150,728	708,678,292		102,539,567
Annual	1,489,450,805		210,347,422	1,489,450,805		228,464,209	1,489,450,805		228,251,417
						228,251,417 [a]			228,251,417 [a]
									0
									100.00%

Notes and Source

[a] Staff proof of revenue, page 2

Fixed Charges	Present	APS Proposed	Staff Proposed
Self contained Meter	$ 20.44	$ 35.28	$ 20.00
Instrument rated meter	$ 40.27	$ 61.44	$ 40.00
Primary Meter	$ 103.87	$ 150.47	$ 100.00

ARIZONA PUBLIC SERVICE COMPANY
General Service Rate E-32 TOU XS - Three-Part
Test Year Ending Dec-15
Proof of Revenue

	Per APS						Per Staff		
Charge	Present Units	Present Rate ($)	Present Revenue ($)	Proposed Units	Proposed Rate ($)	Proposed Revenue ($)	Proposed Units	Proposed Rate ($)	Proposed Revenue ($)
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Summer Days									
Self contained Meter	39,507	0.710	28,050	39,507	1.160	45,828	39,507	0.658	$ 25,977
Instrument rated meter	5,753	1.324	7,617	5,753	2.020	11,621	5,753	1.315	$ 7,566
Primary Meter	-	3.415	-	-	4.947	-	-	3.288	$ -
kW Secondary - on	-	-	-	7,493	4.546	34,063	7,493	4.546	$ 34,063
kW Secondary - off	-	-	-	7,490	2.599	19,467	7,490	2.599	$ 19,467
kW Primary - on				-	3.951		-	3.951	$ -
kW Primary - off				-	1.565		-	1.565	$ -
kWh tier 1 - secondary - on	1,029,226	0.17033	175,308	373,726	0.14870	55,573	373,726	0.15909	$ 59,455
kWh tier 2 - secondary - on	-	0.08564	-			-	-	-	$ -
kWh tier 1 - secondary - off	1,558,884	0.12686	197,760	2,478,317	0.11391	282,305	2,478,317	0.12187	$ 302,024
kWh tier 2 - secondary - off	263,933	0.04755	12,550	-		-	-	-	$ -
kWh tier 1 - primary - on	-	0.16698	-	-	0.14670	-	-	-	$ -
kWh tier 2 - primary - on	-	0.08150	-	-		-	-	-	$ -
kWh tier 1 - primary - off	-	0.12350	-	-	0.10770	-	-	-	$ -
kWh tier 2 - primary - off	-	0.04420	-	-		-	-	-	$ -
Billed kWh, Revenue	2,852,043		421,285	2,852,043		448,857	2,852,043		448,552
Winter Days									
Self contained Meter	39,420	0.710	27,988	39,420	1.160	45,727	39,420	0.658	$ 25,920
Instrument rated meter	7,709	1.324	10,207	7,709	2.020	15,572	7,709	1.315	$ 10,138
Primary Meter	-	3.415	-	-	4.947	-	-	3.288	$ -
kW Secondary - on	-	-	-	8,019	4.546	36,454	8,019	4.546	$ 36,454
kW Secondary - off	-	-	-	11,246	2.599	29,228	11,246	2.599	$ 29,228
kW Primary - on				-	3.951		-	3.951	$ -
kW Primary - off				-	1.565		-	1.565	$ -
kWh tier 1 - secondary - on	979,577	0.15310	149,973	394,916	0.11870	46,877	394,916	0.12699	$ 50,151
kWh tier 2 - secondary - on	-	0.06837	-			-	-	-	$ -
kWh tier 1 - secondary - off	1,551,769	0.10959	170,058	2,703,651	0.09091	245,789	2,703,651	0.09726	$ 262,957
kWh tier 2 - secondary - off	567,221	0.03496	19,830	-		-	-	-	$ -
kWh tier 1 - primary - on	-	0.14974	-	-	0.11670	-	-	-	$ -
kWh tier 2 - primary - on	-	0.06423	-	-		-	-	-	$ -
kWh tier 1 - primary - off	-	0.10624	-	-	0.08470	-	-	-	$ -
kWh tier 2 - primary - off	-	0.03160	-	-		-	-	-	$ -
Billed kWh, Revenue	3,098,567		378,056	3,098,567		419,647	3,098,567		414,849
Riders - Summer	-		-	-		-			
Riders - Winter	-		-	-		-			
Subtotal	-		-	-		-			
Total Billed Revenue	kWh		Revenue	kWh		Revenue	kWh		Revenue
Summer	2,852,043		421,285	2,852,043		448,857	2,852,043		448,552
Winter	3,098,567		378,056	3,098,567		419,647	3,098,567		414,849
Annual	5,950,610		799,341	5,950,610		868,504	5,950,610		863,400
Unbilled kWh, Revenue	(6,909)		(925)	(6,909)		(1,027)			(1,027)
Total Before Adjustments	kWh		Revenue	kWh		Revenue	kWh		Revenue
Summer	2,852,043		421,285	2,852,043		448,857	2,852,043		448,552
Winter	3,091,658		377,131	3,091,658		418,620	3,098,567		413,822
Annual	5,943,701		798,416	5,943,701		867,477	5,950,610		862,373
Test Year Actual Billed Revenue			794,723						
Reconciliation to Test Year			(4,618)			(5,018)			
Summer			(2,434)			(2,593)			(2,593)
Winter			(2,184)			(2,425)			(2,425)
Weather Adustment	kWh	$-kWh	Revenue	kWh	$-kWh	Revenue	kWh	$-kWh	Revenue
Summer	(15,000)	0.13521	(2,028)	(15,000)	0.11847	(1,777)	(15,000)	0.12675	(1,901)
Winter	(26,000)	0.10968	(2,852)	(26,000)	0.09445	(2,456)	(26,000)	0.10105	(2,627)
Annual	(41,000)		(4,880)	(41,000)		(4,233)	(41,000)		(4,528)
Customer Adjustment	kWh	$-kWh	Revenue	kWh	$-kWh	Revenue			Revenue
Summer	16,000	0.14771	2,363	16,000	0.15738	2,518	16,000	0.16837	2,694
Winter	20,000	0.12201	2,440	20,000	0.13543	2,709	20,000	0.14489	2,898
Annual	36,000		4,803	36,000		5,227	36,000		5,592
Limited Income, AG-1 Adjustments			Revenue			Revenue			Revenue
Summer			(1,018)			(1,785)			(1,910)
Winter			(1,103)			(1,936)			(2,071)
Annual			(2,121)			(3,721)			(3,981)
Total Adjustments	kWh		Revenue	kWh		Revenue			Revenue
Summer	1,000		(3,117)	1,000		(3,637)			(3,710)
Winter	(6,000)		(3,699)	(6,000)		(4,108)			(4,226)
Annual	(5,000)		(6,816)	(5,000)		(7,745)			(7,936)
Adjusted Revenue	kWh		Revenue	kWh		Revenue			Revenue
Summer	2,853,043		418,168	2,853,043		445,220			444,842
Winter	3,085,658		373,432	3,085,658		414,512			409,596
Annual	5,938,701		791,600	5,938,701		859,732			854,438
						854,438 [a]			854,438 [a]
									0
									100.0%

Notes and Source
[a] Staff proof of revenue, page 2

Fixed Charges	Present	APS Proposed	Staff Proposed
Self contained Meter	$ 21.60	$ 35.28	$ 20.00
Instrument rated meter	$ 40.27	$ 61.44	$ 40.00
Primary Meter	$ 103.87	$ 150.47	$ 100.00

Arizona Public Service Company
Docket No. E-01345A-16-0036
Attachment RCS-16
Copies of APS's Non-Confidential Responses to Data Requests
and Documents Referenced in the Direct Testimony and Schedules of
Ralph C. Smith

Data Request/ Workpaper No.	Subject	Confidential	No. of Pages	Page No.
Woodward 2.30	APS is withdrawing its initial proposal to charge a one-time set-up fee for a customer without an existing AMI meter requesting to opt-out of APS' standard metering.	No	1	2
Staff 9.18	Number of customers in 2015 with non-AMI meters; Cost differences between the per-meter cost of an AMI meter and a non-AMI meter; Useful lives for AMI meters and non-AMI meters; Detail of derivation of per month setup amounts.	No	6	3 - 8
Woodward 2.10	Explanation for charging customers refusing "smart" meters additional charges for meter reading and set-up; Explanation for charging customers refusing "smart" meters the cost of the smart meters system they are not using, the cost of manually reading the meters, and the cost of manually reading the customer meters that cannot be serviced by a "smart" meter.	No	2	9 - 10
Staff 5.5	Percentage of residential customers that have elected the LFCR opt-out option for APS's 2015 LFCR filing; Percentage of residential customers that have elected to opt out of APS's 2014 LFCR filing.	No	6	11 - 16
Staff 5.56	APS provided the 2016 and 2015 EIS annual reports with supporting workpapers. (Voluminous attachments not included)	No	1	17
Staff 5.81	APS confirmed that all transmission costs as of the Test Year have been used in the base rate revenue requirement determination.	No	1	18
Staff 5.68	APS does not currently have a balancing account associated with the TCA and does not have a formal reconciliation procedure in practice.	No	1	19
Staff 5.69	Revenue billed on a monthly basis for transmission costs and ancillary services for calendar years 2012 through 2015 and year to date 2016 as of August 2016; Comparison of what APS was allowed to recover through base rates and the TCA for calendar years 2012 through 2015 and YTD 2016 as of August 2016.	No	3	20 - 22
Staff 5.7	Actual transmission costs collected through base rate and the TCA as compared to the allowed recovery calculated in the Company's filed annual FERC transmission formula rate for years 2008 through 2015; Proposed recovery in the current case is only for prospective over or under-recovered amounts through the TCA and not historical amounts.	No	1	23
	Total Pages Including this Page		23	

INTERVENOR WARREN WOODWARD'S
SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-16-0036
DECEMBER 5, 2016

Woodward 2.30: Re Table 3 at page 57 of Charles Miessner's testimony:

a. How does APS justify the proposed difference in cost between "After hours Charge--Residential Non-Standard Metering" and "After hours Charge –Nonresidential?" Provide assumptions, details and any and all worksheets.

b. How does APS justify the proposed difference in cost between "Set-up fee for customer with existing AMI meter" and "Set-up fee for customer without existing AMI meter?" Provide assumptions, details and any and all worksheets.

c. Explain what "Meter Reread" is and exactly what it entails.

d. How does APS justify the proposed difference in cost between "Trip Charge –Residential" and "Trip Charge – Nonresidential?" Provide assumptions, details and any and all worksheets.

Response:

a. Please see APS's response to AURA 1.36.

b. APS is withdrawing its initial proposal to charge a one-time set-up fee for a customer without an existing AMI meter requesting to opt-out of APS's standard metering. Customers that have already requested to be served with non-standard metering will not be charged a set-up fee. See the Company's October 11, 2016 follow-up letter to participants at the third APS technical conference.

c. Meter Rereads are defined in APS ACC-approved Service Schedule 1.

d. Please see APS's response to AURA 1.36.

Witness: Chuck Miessner

ARIZONA CORPORATION COMMISSION STAFF'S
NINTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-16-0036
AND
DOCKET NO. E-01345A-16-0123
OCTOBER 11, 2016

Staff 9.18: Customers choosing to not have an AMI meter. Refer to the testimony of APS witness Bordenkircher at pages 9-11.

a. Refer to the table at page 10 listing the number of customers in 2015 with non-AMI meters. Please provide a similar table as of September 30, 2016 showing the number of customers with non-AMI meters as of that date, and include a break-out for each region between (1) residential and (2) commercial.

b. Identify the number of non-AMI meters and the related total and per-meter cost as of each of the following dates: (1) 12/31/2015 and (2) 9/30/2016.

c. Is there a difference between the per-meter cost of (1) an AMI meter and (2) a non-AMI meter? If so, identify, quantify and explain the difference between the per-meter cost of (1) an AMI meter and (2) a non-AMI meter for (i) residential customers and (ii) for commercial customers.

d. Identify the useful lives for (1) AMI meters and (2) non-AMI meters.

e. Is the useful life the same for (1) an AMI meter and (2) a non-AMI meter? If not, explain why there is a difference.

f. Show in detail how the $13.78 per month and $66.79 and $344.59 setup amounts on page 10 were derived.

Response: a. Please see the table below:

Customers Who Have Elected Not to Have AMI Meters as of 9/30/16				
Region of Arizona		**Commercial**	**Residential**	**Total**
Metro Phoenix		130	3,800	3,930
Northeastern	Payson, Show Low, Snowflake	90	1,300	1,390
Northwestern	Prescott, Cottonwood, Sedona, Dewey, Flagstaff	820	9,000	9,820
Southeastern	Casa Grande, Bisbee, Douglas, Globe, Miami	30	500	530
Southwestern	Yuma, Parker, San Luis	20	200	220
Grand Total		**1,090**	**14,800**	**15,890**

Witness: Scott Bordenkircher

ARIZONA CORPORATION COMMISSION STAFF'S
NINTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-16-0036
AND
DOCKET NO. E-01345A-16-0123
OCTOBER 11, 2016

Response to Staff 9.18 continued:

b. Please see the Company's response to Staff 5.39 for number of non-AMI meters and the Company's response to Staff 9.17 for meter cost.

c. Yes, there is a difference between per-meter costs for AMI and digital meters. The costs shown below are 2016 assumptions and include base purchase price, sales tax, and capitalized installation labor:

Single-phase AMI meter (mostly residential)	$120
Three-phase AMI meter (mostly commercial)	$404
Single-phase digital meter (mostly residential)	$104
Three-phase digital meter (mostly commercial)	$451

Prices shown are at market and APS does not have insight into vendor market pricing.

d. APS is proposing a 20-year useful life for both AMI and non-AMI meters in the 2016 depreciation rate study.

e. See the response to subpart d.

f. Please see attachment APSRC01391.

Witness: Scott Bordenkircher

AMI Opt-Out Cost Summary

		2015
Opt-Out deployed meter base		16,568
Summary of Opt-Out Customer Cost		
Monthly Meter Reading & Manual Service Orders		
Meter Reading Opt-Out Cost Per Customer Per Month	$	13.78

Up Front Start-up Cost - Residential		
Total Start Up Cost of Opt-Out Customer	$	66.79

Up front Start-up cost - Commercial		
Total Start Up Cost of Opt-Out Customer	$	334.59

Up Front Fee Calculation	No. / Hr	Per No. / Hr	Cost - Per Meter	Additional Information	
Call Center BSR Creation - 2 minutes per account	2	$29.35	$0.98	2015 average hourly loaded Salary = $ 29.35/ 60 minutes (to get per minute rate) * 2 minutes	
Billing (Process BSR) - 2 minutes per account	2	$33.71	1.12	2015 average hourly loaded salary = $33.71 / 60 minutes (to get per minute rate) * 2 minutes	
Call Center - Turn On (assumes 1 Cust Assoc II for every 15,000 calls)		$4.07	4.07	Based on average Annual 2015 loaded Salary $61,044 / 15000 calls	
AMI Tech Support - 2 minutes per transaction	2	$43.54	$1.45	2015 average hourly loaded salary = $43.54 * 2 minutes	
Meter Backhaul Processing - Base Salary	$72,440	$34.83		Loaded annual 2015 salary $71,570+PC lease $180+uniforms $490 +Misc. supplies $200	
Process 56 meters per day	56	$278.62	$5.00	Based on 8 hours pay / 56 meters per day	
Meter Testing (49 meters/day)	$113,778	$54.70		Mtrmn Elec SI Ph 2015 annual loaded salary $108,757, OT - 4151, uniforms - 490, M&S - 200 and PC lease = 180	
Process 30 meters per day	30	$437.61	$14.59	Based on 8 hours pay / 30 meters per day	
Field Trips Per Customer					
B Servicemen for Residential	2	$19.79	39.58	Based on actual field service costs per order	
Customer Start Up - Residential			**66.79**		
Field Trips Per Customer					
Poly Phase for Commercial	2	$153.69	307.38	Based on actual Meter Shop costs per order excluding Backhaul and Testing costs	
Customer Start Up - Commercial			**334.59**		

AMI Opt-Out Cost Summary
2015 Meter Reads, Order Count and Actual Spending

		Non AMI	AMI	
Total Meters base	**1,272,071**	**20,116**	**1,251,955**	
NE	134,033	3,433	130,600	
NW	79,654	11,026	68,628	
SE	95,317	724	94,593	
SW	859,536	384	859,152	
Metro	103,531	4,549	98,982	
% of Opt Out participation	**1.3%**			% of Non AMI as Opt Out
Opt-Out customer count	**16,568**	**16,432**	**136**	**82%**
NE - Payson, Showlow, Snowflake, etc.	1,856	1,848	8	54%
NW-Prescott, Prescott Valley, Cottonwood, Sedona, Dewey, Flagstaff, etc.	10,352	10,292	60	93%
SE - Casa Grande, Bisbee, Douglas, Globe, Miami	518	514	4	71%
SW - Yuma, Parker, San Luis	232	230	2	60%
Metro	3,610	3,548	62	78%
Total Meter Reading Costs for Non-AMI (Metro and State)	**3,071,131**	Total cost to read Non AMI meters in 2015.		
Average Monthly Per Meter Read Cost (Metro and State)	**$13.64**	82% Non AMI Meter cost is for Opt-Out Customer.		
Average Monthly Per Meter Read Itron cost	**$0.15**			
Total Average Field Services Order Costs	**$19.79**	Average FS cost to roll a truck and change the meter at each site in 2015.		
Total Average Polyphase Order Costs	**153.69**	Average Meter Shop cost to roll a truck and change the meter at each site in 2015.		
Total Opt Out Cost per Customer	**$13.78**			

2015 TOTALS Meter Reading State & Metro			
Desc	Total Reads	Actual Spend	**Cost per Read**
State/Metro	225,190	$3,071,131	$ 13.64

2015 TOTALS Field Services and Meter Shop Order Counts			
Desc	Total Orders	Actual Spend	**Cost Per Order**
Field Services	225,190	$4,456,605	$ 19.79
Meter Shop	26,937	$4,139,941	$ 153.69

2015 Itron Handheld and Software Cost Meter Reading State & Metro	
Desc	Actual Spend
HH Devices	$21,038
Accessories	$6,715
Software	$5,192
Total	$32,944
Per Read	$0.15

INTERVENOR WARREN WOODWARD'S SECOND SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN DOCKET NO. E-01345A-16-0036 DECEMBER 5, 2016

Woodward 2.10: At an APS rate case technical conference it was asserted by APS that there are areas in APS's service territory where, due to remoteness, "smart" meters do not work and will not be used, and that APS is proposing no extra charges for set-up or meter reading to those customers for not having a "smart" meter.

a) Provide locations of these areas and describe why they can't be served.
b) Provide the number of customers affected broken out by class of service.
c) If the mesh communication system does not work in these locations, are there alternative ways to have a "smart" meter in these locations? If yes, then describe.
d) Explain why is it appropriate to charge customers refusing "smart" meters additional charges for meter reading and set-up when other customers will be receiving that same service at no extra charge.
e) Explain why it is appropriate to charge customers refusing "smart" meters the cost of the "smart" meters system they are not using, the cost of manually reading their meters plus the cost of manually reading these customer meters that cannot be serviced by a "smart" meter.

Response:

a) The ability of AMI meters to effectively communicate is dependent on the availability of a cellular network. While cellular availability is limited in remote geographical locations, availability may also be dependent on building configuration, type of building materials, and other topographical or mechanical limitations.

b) The total number of customers without AMI meters due to technical reasons as of year-end 2015 was 3,684. Of these, 1,840 are residential customers and 1,844 are commercial customers.

c) APS's AMI meters by definition are two-way communicating meters. By this definition, the answer to the question is no.

d) Customers who specifically choose to opt out of APS's standard metering when they otherwise could be successfully served via standard metering are causing additional costs for the utility that it would otherwise not have. It is therefore appropriate for those customers who make that choice to bear those costs.

Witness: Bordenkircher/Miessner

INTERVENOR WARREN WOODWARD'S
SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-16-0036
DECEMBER 5, 2016

Response to Woodward 2.10 continued:	e) APS's metering cost structure includes the costs associated with metering all customers via AMI as well the small number of customers who cannot (through any choice of their own) be metered via AMI. These costs are shared by all APS customers. Customers who specifically choose to opt out of APS's standard metering when they otherwise could be successfully served via standard metering are causing additional costs for the utility that it would otherwise not have. It is therefore appropriate for those customers who make that choice to bear those costs.

Witness: Bordenkircher/Miessner

ARIZONA CORPORATION COMMISSION STAFF'S
FIFTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-16-0036
AND
DOCKET NO. E-01345A-16-0123
OCTOBER 4, 2016

Staff 5.5: **Lost Fixed Cost Recovery**. For calendar years 2014 and 2015, show in detail how the LFCR revenue requirement would have been impacted, had each of the following changes that are being requested by APS been in place, and include supporting calculations:

a. increasing the year over year cap to 2%

b. having the costs eligible for recovery to include 100% of generation, customer, transmission, and distribution costs collected through energy charges and 50% of the generation, transmission,

c. removing the LFCR opt-out rate option

d. applying the LFFCR to customer bills as a per-kWh charge for customers under a two-part rate and a per-kW charge for customers taking service under a three-part rate

Response: For purposes of this question, APS has assumed all proposed changes to the LFCR are in effect unless otherwise stated.
Please see attachment APSRC01333 for the following:

a. Increasing the cap would not change the revenue requirement. Under the current 1% cap, amounts above the cap are carried forward for future recovery. If however, the cap were increased to 2%, annual collections would increase and the carryover would be reduced or eliminated. APS estimates the additional collections for 2014 and 2015 would be \$19.5 M and \$26.7 M respectively. These are amounts that APS should collect based upon the revenue requirement authorized by the Commission but did not because of Commission policies regarding DG and EE.

b. Applying the proposed changes to today's rates would have increased the revenue requirement by \$40M in 2014 and \$60M in 2015. These are amounts that APS should have collected based upon the revenue requirement authorized by the Commission but did not because of Commission

ARIZONA CORPORATION COMMISSION STAFF'S
FIFTH SET OF DATA REQUESTS TO
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DOCKET NO. E-01345A-16-0123
OCTOBER 4, 2016

policies regarding DG and EE.

APS's proposed rate structure will have more demand components thus reducing the lost fixed cost rate in turn reducing the overall revenue requirement of the LFCR.

c. Removing the LFCR Opt-Out would increase the revenue requirement by $80,000 in 2015 and $73,000 in 2014 using the proposed lost fixed cost rate.

d. Applying the LFCR as a $ per kWh or $ per kW charge would have no effect on the LFCR revenue requirement, because the magnitude of the charge would be designed to collect the same revenue requirement.

SUMMARY

	($000)	
	2015 Filing	2014 Filing
LFCR Revenue Requirement (Filed)	38,505	25,352
LFCR Revenue Requirement (Proposed Method 2%)	98,708	65,135
Increase in Revenue Requirement	60,203	39,783

	($000)	
	2015 Filing	2014 Filing
LFCR Revenue Requirement (Filed)	38,505	25,352
LFCR Revenue Requirement (Proposed Method 1%)	72,021	45,634
Increase in Revenue Requirement	33,516	20,282
2% vs 1%	$ 26,687	$ 19,501

Schedule 1 Line No.	(A) Annual Percentage Adjustment	(B) Reference	(C) 2015 Filing	(C) 2014 Filing
1.	Total Lost Fixed Cost Revenue for Current Period	Schedule 2, Line 15	$ 38,505	$ 25,352

Schedule 2 Line No.	(A) LFCR Annual Incremental Cap Calculation	(B) Reference	2015 Filing	2014 Filing
1.	Applicable Company Revenues		$ 2,638,712	$ 2,666,032
2.	Allowed Cap %		1.00%	1.00%
3.	Maximum Allowed Incremental Recovery	(Line 1 * Line 2)	$ 26,387	$ 26,660
4.	Total Lost Fixed Cost Revenue	Schedule 3, Line 38, Column C	$ 34,451	$ 22,606
5.	Total Deferred Balance from Previous Period	Previous Filing, Schedule 2, Line 13, Column C	-	-
6.	Annual Interest Rate		0.25%	0.13%
7.	Interest Accrued on Deferred Balance	(Line 5 * Line 6)	-	-
8.	Total Lost Fixed Cost Revenue Current Period	(Line 4 + Line 5 + Line 7)	$ 34,451	$ 22,606
9.	Lost Fixed Cost Revenue from Prior Period	Previous Filing, Schedule 2, Line 15, Column C	$ 25,352	$ 7,345
10.	Lost Fixed Cost Revenue - Billed[1]		$ 21,298	$ 4,599
11.	LFCR Balancing Account	(Line 9 - Line 10)	$ 4,054	$ 2,746
12.	Total Incremental Lost Fixed Cost Revenue for Current Year	(Line 8 - Line 9 + Line 11)	$ 13,153	$ 18,007
13.	Amount in Excess of Cap to Defer	(Line 12 - Line 3)	$ -	$ -
14.	Incremental Period Adjustment as %	[(Line 12 - Line 13) / Line 1]	0.4985%	0.6754%
15.	Total Lost Fixed Cost Revenue for Current Period	(Line 8 + Line 11 - Line 13)	$ 38,505	$ 25,352

[1] Includes LFCR DG Revenue

Schedule 3 Line No.	(A) Lost Fixed Cost Revenue Calculation	(B) Reference	2015 Filing	2014 Filing	(D) Units
	Residential				
	Energy Efficiency Savings				
1.	Current Period		175,631	220,905	MWh
2.	% of Residential Customers on Opt-Out		0.302%	0.273%	
3.	Excluded MWh reduction	(Line 1 * Line 2)	530	604	MWh
4.	Net - Current Period	(Line 1 - Line 3)	175,101	220,301	MWh
5.	Prior Period	Previous Filing, Schedule 3, Line 4, Column C	220,301	103,000	MWh
6.	Verified - Prior Period		220,071	108,734	MWh
7.	True-Up Prior Period	(Line 6 - Line 5)	(230)	5,734	MWh
8.	Cumulative Verified	(Previous Filing, Schedule 3, Line 8, Column C + Line 6)	328,805	108,734	MWh
9.	Total Recoverable EE Savings	(Line 4 + Line 7 + Line 8)	503,677	334,769	MWh
	Distributed Generation Savings				
10.	Current Period		230,731	139,032	MWh
11.	Excluded MWh Production		556	380	MWh
12.	Net - Current Period	(Line 10 - Line 11)	230,175	138,652	MWh
13.	Prior Period	Previous Filing, Schedule 3, Line 12, Column C	138,652	44,103	MWh
14.	Verified - Prior Period		135,183	46,609	MWh
15.	True-Up Prior Period	(Line 14 - Line 13)	(3,469)	2,506	MWh
16.	Total Recoverable DG Savings	(Line 12 + Line 15)	226,706	141,158	MWh
17.	Total Recoverable MWh Savings	(Line 9 + Line 16)	730,383	475,927	MWh
18.	Residential - Lost Fixed Cost Rate	Schedule 4, Line 5, Column C	$ 0.031111	$ 0.031111	$/kWh
19.	Residential - Lost Fixed Cost Revenue	(Line 17 * Line 18)	$ 22,723	$ 14,807	
	C&I				
	Energy Efficiency Savings				
20.	Current Period		198,133	211,505	MWh
21.	Excluded MWh reduction		72,946	61,691	MWh
22.	Net - Current Period	(Line 20 - Line 21)	125,187	149,814	MWh
23.	Prior Period	Previous Filing, Schedule 3, Line 22, Column C	149,814	92,617	MWh
24.	Verified - Prior Period		148,374	92,226	MWh
25.	True-Up Prior Period	(Line 24 - Line 23)	(1,440)	(391)	MWh
26.	Cumulative Verified	(Previous Filing, Schedule 3, Line 26, Column C + Line 24)	240,600	92,226	MWh
27.	Total Recoverable EE Savings	(Line 22 + Line 25 + Line 26)	364,347	241,649	MWh
	Distributed Generation Savings				
28.	Current Period		186,458	144,422	MWh
29.	MWh DG Savings from Rate Schedules Excluded from LFCR		60,420	56,389	MWh
30.	Net - Current Period	(Line 28 - Line 29)	126,038	88,033	MWh
31.	Prior Period	Previous Filing, Schedule 3, Line 30, Column C	88,033	26,764	MWh
32.	Verified - Prior Period		103,385	33,411	MWh
33.	True-Up Prior Period	(Line 32 - Line 31)	15,352	6,647	MWh
34.	Total Recoverable DG Savings	(Line 30 + Line 33)	141,390	94,680	MWh
35.	Total Recoverable MWh Savings	(Line 27 + Line 34)	505,737	336,329	MWh
36.	C&I - Lost Fixed Cost Rate	Schedule 4, Line 10, Column C	$ 0.023190	$ 0.023190	$/kWh
37.	C&I - Lost Fixed Cost Revenue	(Line 35 * Line 36)	$ 11,728	$ 7,799	
38.	**Total Lost Fixed Cost Revenue**	**(Line 19 + Line 37)**	**$ 34,451**	**$ 22,606**	

Schedule 4 Line No.	(A) Lost Fixed Cost Rate Calculation	(B) Reference	(C) 2015 Filing	(C) 2014 Filing
	Residential Customers			
1.	Distribution Revenue		$ 326,735	$ 326,735
2.	Transmission Revenue		$ 65,572	$ 65,572
3.	Total Fixed Revenue	(Line 1 + Line 2)	$ 392,307	$ 392,307
4.	MWh Billed		12,610,002	12,610,002
5.	Lost Fixed Cost Rate	(Line 3 / Line 4)	$ 0.031111	$ 0.031111
	C & I Customers			
6.	Distribution Revenue		$ 155,931	$ 155,931
7.	Transmission Revenue		$ 23,093	$ 23,093
8.	Total Fixed Revenue	(Line 6 + Line 7)	$ 179,024	$ 179,024
9.	MWh Billed		7,719,982	7,719,982
10.	Lost Fixed Cost Rate	(Line 8 / Line 9)	$ 0.023190	$ 0.023190

Schedule 1 Line No.	(A) Annual Percentage Adjustment	(B) Reference	(C) 2015 Filing	(C) 2014 Filing
1.	Total Lost Fixed Cost Revenue for Current Period	Schedule 2, Line 15	$ 98,708	$ 65,135

Schedule 2 Line No.	(A) LFCR Annual Incremental Cap Calculation	(B) Reference	2015 Filing	2014 Filing
1.	Applicable Company Revenues		$ 2,638,712	$ 2,666,032
2.	Allowed Cap %		2.00%	2.00%
3.	Maximum Allowed Incremental Recovery	(Line 1 * Line 2)	$ 52,774	$ 53,321
4.	Total Lost Fixed Cost Revenue	Schedule 3, Line 38, Column C	$ 88,292	$ 58,041
5.	Total Deferred Balance from Previous Period	Previous Filing, Schedule 2, Line 13, Column C	-	-
6.	Annual Interest Rate		0.25%	0.13%
7.	Interest Accrued on Deferred Balance	(Line 5 * Line 6)	-	-
8.	Total Lost Fixed Cost Revenue Current Period	(Line 4 + Line 5 + Line 7)	$ 88,292	$ 58,041
9.	Lost Fixed Cost Revenue from Prior Period	Previous Filing, Schedule 2, Line 15, Column C	$ 65,135	$ 18,974
10.	Lost Fixed Cost Revenue - Billed[1]		$ 54,719	$ 11,880
11.	LFCR Balancing Account	(Line 9 - Line 10)	$ 10,416	$ 7,094
12.	Total Incremental Lost Fixed Cost Revenue for Current Year	(Line 8 - Line 9 + Line 11)	$ 33,573	$ 46,161
13.	Amount in Excess of Cap to Defer	(Line 12 - Line 3)	$ -	$ -
14.	Incremental Period Adjustment as %	[(Line 12 - Line 13) / Line 1]	1.2723%	1.7314%
15.	Total Lost Fixed Cost Revenue for Current Period	(Line 8 + Line 11 - Line 13)	$ 98,708	$ 65,135

[1]Includes LFCR DG Revenue

Schedule 3 Line No.	(A) Lost Fixed Cost Revenue Calculation	(B) Reference	2015 Filing	2014 Filing	(D) Units
	Residential				
	Energy Efficiency Savings				
1.	Current Period		175,631	220,905	MWh
2.	% of Residential Customers on Opt-Out		0.000%	0.000%	
3.	Excluded MWh reduction	(Line 1 * Line 2)	-	-	MWh
4.	Net - Current Period	(Line 1 - Line 3)	175,631	220,905	MWh
5.	Prior Period	Previous Filing, Schedule 3, Line 4, Column C	220,905	103,000	MWh
6.	Verified - Prior Period		220,071	108,734	MWh
7.	True-Up Prior Period	(Line 6 - Line 5)	(834)	5,734	MWh
8.	Cumulative Verified	(Previous Filing, Schedule 3, Line 8, Column C + Line 6)	328,805	108,734	MWh
9.	Total Recoverable EE Savings	(Line 4 + Line 7 + Line 8)	503,603	335,373	MWh
	Distributed Generation Savings				
10.	Current Period		230,731	139,032	MWh
11.	Excluded MWh Production		556	380	MWh
12.	Net - Current Period	(Line 10 - Line 11)	230,175	138,652	MWh
13.	Prior Period	Previous Filing, Schedule 3, Line 12, Column C	138,652	44,103	MWh
14.	Verified - Prior Period		135,183	46,609	MWh
15.	True-Up Prior Period	(Line 14 - Line 13)	(3,469)	2,506	MWh
16.	Total Recoverable DG Savings	(Line 12 + Line 15)	226,706	141,158	MWh
17.	Total Recoverable MWh Savings	(Line 9 + Line 16)	730,309	476,531	MWh
18.	Residential - Lost Fixed Cost Rate	Schedule 4, Line 5, Column C	$ 0.073861	$ 0.073861	$/kWh
19.	Residential - Lost Fixed Cost Revenue	(Line 17 * Line 18)	$ 53,941	$ 35,197	
	C&I				
	Energy Efficiency Savings				
20.	Current Period		198,133	211,505	MWh
21.	Excluded MWh reduction		72,946	61,691	MWh
22.	Net - Current Period	(Line 20 - Line 21)	125,187	149,814	MWh
23.	Prior Period	Previous Filing, Schedule 3, Line 22, Column C	149,814	92,617	MWh
24.	Verified - Prior Period		148,374	92,226	MWh
25.	True-Up Prior Period	(Line 24 - Line 23)	(1,440)	(391)	MWh
26.	Cumulative Verified	(Previous Filing, Schedule 3, Line 26, Column C + Line 24)	240,600	92,226	MWh
27.	Total Recoverable EE Savings	(Line 22 + Line 25 + Line 26)	364,347	241,649	MWh
	Distributed Generation Savings				
28.	Current Period		186,458	144,422	MWh
29.	MWh DG Savings from Rate Schedules Excluded from LFCR		60,420	56,389	MWh
30.	Net - Current Period	(Line 28 - Line 29)	126,038	88,033	MWh
31.	Prior Period	Previous Filing, Schedule 3, Line 30, Column C	88,033	26,764	MWh
32.	Verified - Prior Period		103,385	33,411	MWh
33.	True-Up Prior Period	(Line 32 - Line 31)	15,352	6,647	MWh
34.	Total Recoverable DG Savings	(Line 30 + Line 33)	141,390	94,680	MWh
35.	Total Recoverable MWh Savings	(Line 27 + Line 34)	505,737	336,329	MWh
36.	C&I - Lost Fixed Cost Rate	Schedule 4, Line 10, Column C	$ 0.067923	$ 0.067923	$/kWh
37.	C&I - Lost Fixed Cost Revenue	(Line 35 * Line 36)	$ 34,351	$ 22,844	
38.	**Total Lost Fixed Cost Revenue**	**(Line 19 + Line 37)**	**$ 88,292**	**$ 58,041**	

Schedule 4 Line No.	(A) Lost Fixed Cost Rate Calculation	(B) Reference	(C) 2015 Filing	(C) 2014 Filing
	Residential Customers			
1.	Total Fixed Revenue ($000)	(Line 1 + Line 2)	$ 931,390	$ 931,390
2.	MWh Billed	Schedule 6, Line 12, Column C / 1,000	12,610,002	12,610,002
3.	Lost Fixed Cost Rate	(Line 3 / Line 4)	$ 0.073861	$ 0.073861
	C & I Customers			
3.	Total Fixed Revenue	(Line 6 + Line 7)	$ 526,625	$ 526,625
4.	MWh Billed	Schedule 5, Line 12, Column C / 1,000	7,753,255	7,753,255
5.	Lost Fixed Cost Rate	(Line 8 / Line 9)	$ 0.067923	$ 0.067923

Schedule 1 Line No.	(A) Annual Percentage Adjustment	(B) Reference	(C) 2015 Filing	(C) 2014 Filing
1.	Total Lost Fixed Cost Revenue for Current Period	Schedule 2, Line 15	$ 72,021	$ 45,634

Schedule 2 Line No.	(A) LFCR Annual Incremental Cap Calculation	(B) Reference	2015 Filing	2014 Filing
1.	Applicable Company Revenues		$ 2,638,712	$ 2,666,032
2.	Allowed Cap %		1.00%	1.00%
3.	Maximum Allowed Incremental Recovery	(Line 1 * Line 2)	$ 26,387	$ 26,660
4.	Total Lost Fixed Cost Revenue	Schedule 3, Line 38, Column C	$ 88,292	$ 58,041
5.	Total Deferred Balance from Previous Period	Previous Filing, Schedule 2, Line 13, Column C	19,501	-
6.	Annual Interest Rate		0.25%	0.13%
7.	Interest Accrued on Deferred Balance	(Line 5 * Line 6)	49	-
8.	Total Lost Fixed Cost Revenue Current Period	(Line 4 + Line 5 + Line 7)	$ 107,842	$ 58,041
9.	Lost Fixed Cost Revenue from Prior Period	Previous Filing, Schedule 2, Line 15, Column C	$ 45,634	$ 18,974
10.	Lost Fixed Cost Revenue - Billed[1]		$ 38,337	$ 11,880
11.	LFCR Balancing Account	(Line 9 - Line 10)	$ 7,297	$ 7,094
12.	Total Incremental Lost Fixed Cost Revenue for Current Year	(Line 8 - Line 9 + Line 11)	$ 69,505	$ 46,161
13.	Amount in Excess of Cap to Defer	(Line 12 - Line 3)	$ 43,118	$ 19,501
14.	Incremental Period Adjustment as %	[(Line 12 - Line 13) / Line 1]	1.0000%	1.0000%
15.	Total Lost Fixed Cost Revenue for Current Period	(Line 8 + Line 11 - Line 13)	$ 72,021	$ 45,634

[1]Includes LFCR DG Revenue

Schedule 3 Line No.	(A) Lost Fixed Cost Revenue Calculation	(B) Reference	2015 Filing	2014 Filing	(D) Units
	Residential				
	Energy Efficiency Savings				
1.	Current Period		175,631	220,905	MWh
2.	% of Residential Customers on Opt-Out		0.000%	0.000%	
3.	Excluded MWh reduction	(Line 1 * Line 2)	-	-	MWh
4.	Net - Current Period	(Line 1 - Line 3)	175,631	220,905	MWh
5.	Prior Period	Previous Filing, Schedule 3, Line 4, Column C	220,905	103,000	MWh
6.	Verified - Prior Period		220,071	108,734	MWh
7.	True-Up Prior Period	(Line 6 - Line 5)	(834)	5,734	MWh
8.	Cumulative Verified	(Previous Filing, Schedule 3, Line 8, Column C + Line 6)	328,805	108,734	MWh
9.	Total Recoverable EE Savings	(Line 4 + Line 7 + Line 8)	503,603	335,373	MWh
	Distributed Generation Savings				
10.	Current Period		230,731	139,032	MWh
11.	Excluded MWh Production		556	380	MWh
12.	Net - Current Period	(Line 10 - Line 11)	230,175	138,652	MWh
13.	Prior Period	Previous Filing, Schedule 3, Line 12, Column C	138,652	44,103	MWh
14.	Verified - Prior Period		135,183	46,609	MWh
15.	True-Up Prior Period	(Line 14 - Line 13)	(3,469)	2,506	MWh
16.	Total Recoverable DG Savings	(Line 12 + Line 15)	226,706	141,158	MWh
17.	Total Recoverable MWh Savings	(Line 9 + Line 16)	730,309	476,531	MWh
18.	Residential - Lost Fixed Cost Rate	Schedule 4, Line 5, Column C	$ 0.073861	$ 0.073861	$/kWh
19.	Residential - Lost Fixed Cost Revenue	(Line 17 * Line 18)	$ 53,941	$ 35,197	
	C&I				
	Energy Efficiency Savings				
20.	Current Period		198,133	211,505	MWh
21.	Excluded MWh reduction		72,946	61,691	MWh
22.	Net - Current Period	(Line 20 - Line 21)	125,187	149,814	MWh
23.	Prior Period	Previous Filing, Schedule 3, Line 22, Column C	149,814	92,617	MWh
24.	Verified - Prior Period		148,374	92,226	MWh
25.	True-Up Prior Period	(Line 24 - Line 23)	(1,440)	(391)	MWh
26.	Cumulative Verified	(Previous Filing, Schedule 3, Line 26, Column C + Line 24)	240,600	92,226	MWh
27.	Total Recoverable EE Savings	(Line 22 + Line 25 + Line 26)	364,347	241,649	MWh
	Distributed Generation Savings				
28.	Current Period		186,458	144,422	MWh
29.	MWh DG Savings from Rate Schedules Excluded from LFCR		60,420	56,389	MWh
30.	Net - Current Period	(Line 28 - Line 29)	126,038	88,033	MWh
31.	Prior Period	Previous Filing, Schedule 3, Line 30, Column C	88,033	26,764	MWh
32.	Verified - Prior Period		103,385	33,411	MWh
33.	True-Up Prior Period	(Line 32 - Line 31)	15,352	6,647	MWh
34.	Total Recoverable DG Savings	(Line 30 + Line 33)	141,390	94,680	MWh
35.	Total Recoverable MWh Savings	(Line 27 + Line 34)	505,737	336,329	MWh
36.	C&I - Lost Fixed Cost Rate	Schedule 4, Line 10, Column C	$ 0.067923	$ 0.067923	$/kWh
37.	C&I - Lost Fixed Cost Revenue	(Line 35 * Line 36)	$ 34,351	$ 22,844	
38.	**Total Lost Fixed Cost Revenue**	**(Line 19 + Line 37)**	**$ 88,292**	**$ 58,041**	

Schedule 4 Line No.	(A) Lost Fixed Cost Rate Calculation	(B) Reference	(C) 2015 Filing	(C) 2014 Filing
	Residential Customers			
1.	Total Fixed Revenue ($000)	(Line 1 + Line 2)	$ 931,390	$ 931,390
2.	MWh Billed	Schedule 6, Line 12, Column C / 1,000	12,610,002	12,610,002
3.	Lost Fixed Cost Rate	(Line 3 / Line 4)	$ 0.073861	$ 0.073861
	C & I Customers			
3.	Total Fixed Revenue	(Line 6 + Line 7)	$ 526,625	$ 526,625
4.	MWh Billed	Schedule 5, Line 12, Column C / 1,000	7,753,255	7,753,255
5.	Lost Fixed Cost Rate	(Line 8 / Line 9)	$ 0.067923	$ 0.067923

ARIZONA CORPORATION COMMISSION STAFF'S
FIFTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-16-0036
AND
DOCKET NO. E-01345A-16-0123
OCTOBER 4, 2016

Staff 5.56: **Environmental Improvement Surcharge (EIS):** Please provide the two most recent EIS annual reports filed with the Commission and include all supporting workpapers and Excel files.

Response: For the 2016 EIS filing and supporting Excel workbook, please see attachments APSRC01192 and APSRC01193.

For the 2015 EIS filing and supporting Excel workbook, please see attachments APSRC01194 and APSRC01195.

Additionally, please note that the 2016 and 2015 filings were made under Docket No. E-01345A-11-0224 (Decision No. 73183) on January 28, 2016 and January 30, 2015, respectively.

Witness: Leland Snook

ARIZONA CORPORATION COMMISSION STAFF'S FIFTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN DOCKET NO. E-01345A-16-0036 AND DOCKET NO. E-01345A-16-0123 OCTOBER 4, 2016

Staff 5.81: **Transmission Cost Adjustment (TCA)**. Please confirm that APS has included all costs associated with transmission in the ACC jurisdictional cost of service in the current base rate revenue requirement determination. If this cannot be confirmed, explain fully why not, and identify the amounts of the transmission cost of service that would need to be reflected in the base rate revenue requirement.

Response: Yes, all transmission costs as of the Test Year have been used in the base rate revenue requirement determination.

Witness: Leland Snook

ARIZONA CORPORATION COMMISSION STAFF'S
FIFTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-16-0036
AND
DOCKET NO. E-01345A-16-0123
OCTOBER 4, 2016

Staff 5.68: **Transmission Cost Adjustment (TCA):** Please provide the current reconciliation procedures for over and under recoveries related to transmission costs and the TCA.

Response: Currently, there is not a balancing account associated with the TCA and therefore, we do not have a formal reconciliation procedure in practice. However, several of APS's adjustor mechanisms currently contain balancing accounts in which there is a formal reconciliation process in place. To ensure that the TCA only reflects actual costs, APS proposes that a formal reconciliation process be created for the TCA. Specifically, as proposed in our Transmission Cost Adjustment Plan of Administration, APS will maintain accounting records that accumulate the difference between the calculated TCA rates as compared to the actual transmission revenues received by the Company through the TCA and base rates during the rate effective period (June through May). Any difference will be recorded to the TCA Balancing Account each month and will be provided annually in the filing. In the event that the TCA is more or less than the revenues collected as of the last billing cycle of May, the over or under collection will be subtracted from or added to the TCA calculation in the subsequent period.

Witness: Leland Snook

ARIZONA CORPORATION COMMISSION STAFF'S
FIFTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
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DOCKET NO. E-01345A-16-0036
AND
DOCKET NO. E-01345A-16-0123
OCTOBER 4, 2016

Staff 5.69: **Transmission Cost Adjustment (TCA):** For each year 2012-2015 and year to date 2016, please provide a schedule that shows the Company's actual total transmission costs compared to what the Company was allowed to recover through base rates and the existing TCA. Please provide by FERC account and month.

Response: Attached is APSRC01237 that presents on a monthly basis the revenue billed for transmission costs and ancillary services for calendar years 2012 - 2015 and year-to-date 2016. Please note that the year-to-date 2016 revenue billed represents eight months of Company data and is subject to change at year end when the full year of revenue is available and finalized. The amount of retail transmission revenue requirement as calculated in the Company's filed annual FERC transmission formula rate is also identified. The revenue requirement associated with ancillary services has been included.

Residential revenues are booked to FERC revenue account 440 and general service revenues are booked to FERC revenue account 442.

Witness: Leland Snook

ARIZONA PUBLIC SERVICE COMPANY
Retail OATT Revenue Analysis
Calendar Years 2012 - 2016

Calendar Year 2012

Line	OATT Revenues Collected thru Customer Bills		6/1/2012 7/	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
1	Residential (kWh)	$ 0.009413	$ 0.010605	$ 9,354,013	$ 8,068,580	$ 7,693,447	$ 7,253,774	$ 9,038,101	$ 12,486,686	$ 15,747,219	$ 17,577,501	$ 16,899,512	$ 11,631,745	$ 8,394,456	$ 9,044,124	$ 133,189,158
2	General Service < 3MW (Non-Demand)(kWh)	$ 0.006703	$ 0.006789	$ 874,009	$ 890,136	$ 841,597	$ 832,884	$ 810,935	$ 927,909	$ 1,120,195	$ 1,208,821	$ 962,902	$ 840,081	$ 1,374,805	$ 1,359,756	$ 12,044,031
		Filed Rate	Filed Rate													
3	General Service < 3MW (Demand)(kW)	$ 2.422	$ 2.397	$ 5,073,114	$ 4,988,194	$ 5,040,672	$ 5,435,713	$ 5,916,486	$ 6,230,981	$ 6,593,721	$ 6,777,743	$ 6,590,505	$ 6,098,006	$ 5,562,966	$ 5,319,230	$ 69,627,331
4	General Service over 3MW (kW)	$ 2.391	$ 2.524	$ 1,008,055	$ 1,014,058	$ 1,041,564	$ 1,085,892	$ 1,145,380	$ 1,184,782	$ 1,276,721	$ 1,352,391	$ 1,317,171	$ 1,211,068	$ 1,161,549	$ 1,123,669	$ 13,922,299
5	Total Transmission Revenues			$ 16,309,191	$ 14,960,967	$ 14,617,279	$ 14,608,264	$ 16,910,903	$ 20,830,360	$ 24,737,856	$ 26,916,456	$ 25,770,091	$ 19,780,900	$ 16,493,775	$ 16,846,779	$ 228,782,819

7/ 2011 Calendar Year Transmission Formula Rate (NITS & Ancillary Services)

2011 Calendar Year Transmission Formula Rate Retail Revenue Requirement ($208,967,788) plus Ancillary Services. $ 235,366,103

Over/(Under) Recovery $ (6,583,284)

Calendar Year 2013

Line	OATT Revenues Collected thru Customer Bills		6/1/2013 7/	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
1	Residential (kWh)	$ 0.010605	$ 0.011673	$ 11,484,678	$ 9,702,871	$ 8,563,809	$ 7,947,662	$ 9,999,026	$ 15,423,192	$ 19,829,110	$ 18,957,278	$ 17,942,957	$ 11,263,025	$ 8,517,109	$ 10,621,193	$ 150,251,910
2	General Service < 3MW (Non-Demand)(kWh)	$ 0.006789	$ 0.006742	$ 1,529,046	$ 846,824	$ 812,476	$ 808,620	$ 872,326	$ 984,720	$ 1,025,307	$ 1,079,415	$ 889,371	$ 842,096	$ 823,319	$ 901,647	$ 11,415,168
		Filed Rate	Filed Rate													
3	General Service < 3MW (Demand)(kW)	$ 2.397	$ 2.433	$ 5,410,112	$ 5,462,161	$ 5,418,288	$ 5,436,551	$ 5,667,416	$ 6,073,488	$ 6,589,433	$ 6,610,830	$ 6,578,756	$ 5,852,991	$ 5,415,204	$ 5,431,661	$ 69,946,890
4	General Service over 3MW (kW)	$ 2.524	$ 3.081	$ 1,163,792	$ 1,155,032	$ 1,167,752	$ 1,196,884	$ 1,223,155	$ 1,541,879	$ 1,664,615	$ 1,660,114	$ 1,679,424	$ 1,523,231	$ 1,492,731	$ 1,484,902	$ 16,953,511
5	Total Transmission Revenues			$ 19,587,628	$ 17,166,888	$ 15,962,326	$ 15,389,717	$ 17,761,922	$ 24,023,278	$ 29,108,465	$ 28,307,637	$ 27,090,507	$ 19,481,343	$ 16,248,362	$ 18,439,405	$ 248,567,479

7/ 2012 Calendar Year Transmission Formula Rate (NITS & Ancillary Services)

2012 Calendar Year Transmission Formula Rate Retail Revenue Requirement ($229,731,731) plus Ancillary Services. $ 256,034,305

Over/(Under) Recovery $ (7,466,826)

Calendar Year 2014

Line	OATT Revenues Collected thru Customer Bills		6/1/2014 7/	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
1	Residential (kWh)	$ 0.011673	$ 0.012205	$ 11,158,627	$ 9,331,300	$ 8,235,582	$ 8,446,176	$ 9,966,985	$ 15,419,153	$ 19,370,860	$ 19,951,000	$ 18,254,491	$ 13,548,981	$ 10,291,657	$ 10,330,198	$ 154,305,010
2	General Service < 3MW (Non-Demand)(kWh)	$ 0.006742	$ 0.006849	$ 897,828	$ 846,535	$ 828,649	$ 805,120	$ 826,453	$ 925,275	$ 997,325	$ 1,013,916	$ 1,024,772	$ 909,044	$ 868,342	$ 913,814	$ 10,857,074
		Filed Rate	Filed Rate													
3	General Service < 3MW (Demand)(kW)	$ 2.433	$ 2.406	$ 5,321,721	$ 5,243,317	$ 5,250,080	$ 5,449,092	$ 5,727,762	$ 6,090,988	$ 6,342,778	$ 6,609,319	$ 6,308,714	$ 6,179,625	$ 5,567,435	$ 5,198,431	$ 69,289,261
4	General Service over 3MW (kW)	$ 3.081	$ 2.943	$ 1,492,401	$ 1,471,230	$ 1,481,948	$ 1,522,208	$ 1,509,635	$ 1,552,389	$ 1,678,452	$ 1,643,937	$ 1,607,906	$ 1,530,319	$ 1,475,751	$ 1,438,492	$ 18,404,667
5	Total Transmission Revenues			$ 18,870,577	$ 16,892,382	$ 15,796,259	$ 16,222,596	$ 18,030,836	$ 23,987,805	$ 28,389,414	$ 29,218,172	$ 27,195,882	$ 22,167,969	$ 18,203,185	$ 17,880,936	$ 252,856,013

7/ 2013 Calendar Year Transmission Formula Rate (NITS & Ancillary Services)

2013 Calendar Year Transmission Formula Rate Retail Revenue Requirement ($234,415,057) plus Ancillary Services. $ 260,158,177

Over/(Under) Recovery $ (7,302,164)

ARIZONA PUBLIC SERVICE COMPANY
Retail OATT Revenue Analysis
Calendar Years 2012 - 2016

Calendar Year 2015

Line	OATT Revenues Collected thru Customer Bills		6/1/2015 7/	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
1	Residential (kWh)	$ 0.012205	$ 0.011767	$ 12,217,928	$ 9,399,130	$ 8,863,899	$ 9,289,350	$ 9,923,072	$ 13,300,049	$ 19,404,409	$ 19,522,579	$ 19,638,673	$ 14,272,021	$ 9,670,553	$ 10,906,858	$ 156,408,520
2	General Service < 3MW (Non-Demand)(kWh)	$ 0.006849	$ 0.007193	$ 920,439	$ 879,864	$ 969,557	$ 940,654	$ 858,191	$ 1,077,590	$ 1,215,522	$ 1,380,473	$ 1,279,461	$ 1,010,481	$ 1,051,413	$ 1,160,560	$ 12,744,207
		Filed Rate	Filed Rate													
3	General Service < 3MW (Demand)(kW)	$ 2.406	$ 2.532	$ 5,362,397	$ 5,163,469	$ 5,295,254	$ 5,447,172	$ 5,522,011	$ 6,360,385	$ 6,777,593	$ 6,916,609	$ 6,889,960	$ 6,466,698	$ 5,815,448	$ 5,546,688	$ 71,563,686
4	General Service over 3MW (kW)	$ 2.943	$ 2.953	$ 1,444,028	$ 1,447,354	$ 1,439,319	$ 1,474,765	$ 1,490,745	$ 1,568,616	$ 1,645,841	$ 1,680,459	$ 1,632,872	$ 1,590,145	$ 1,496,712	$ 1,394,197	$ 18,305,052
5	Total Transmission Revenues			$ 19,944,793	$ 16,889,818	$ 16,568,029	$ 17,151,940	$ 17,794,019	$ 22,306,640	$ 29,043,364	$ 29,500,120	$ 29,440,965	$ 23,339,345	$ 18,034,128	$ 19,008,303	$ 259,021,464

7/ 2014 Calendar Year Transmission Formula Rate (NITS & Ancillary Services)

2014 Calendar Year Transmission Formula Rate Retail Revenue Requirement ($227,281,497) plus Ancillary Services. $ 253,601,242

Over/(Under) Recovery $ 5,420,222

Calendar Year 2016-Estimate

Line	OATT Revenues Collected thru Customer Bills		6/1/2016 7/	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
1	Residential (kWh)	$ 0.011767	$ 0.012347	$ 12,496,314	$ 10,242,752	$ 8,283,387	$ 8,575,080	$ 9,584,928	$ 15,405,115	$ 21,367,574	$ 21,732,794	$ -	$ -	$ -	$ -	$ 107,687,943
2	General Service < 3MW (Non-Demand)(kWh)	$ 0.007193	$ 0.008100	$ 1,253,509	$ 1,098,147	$ 1,051,819	$ 985,642	$ 1,010,989	$ 1,234,811	$ 1,408,393	$ 1,426,609	$ -	$ -	$ -	$ -	$ 9,469,919
		Filed Rate	Filed Rate													
3	General Service < 3MW (Demand)(kW)	$ 2.532	$ 2.835	$ 5,608,008	$ 5,612,773	$ 5,446,802	$ 5,691,272	$ 5,862,202	$ 7,365,045	$ 7,762,592	$ 7,790,353	$ -	$ -	$ -	$ -	$ 51,139,047
4	General Service over 3MW (kW)	$ 2.953	$ 3.218	$ 1,441,610	$ 1,443,851	$ 1,443,931	$ 1,452,831	$ 1,474,826	$ 1,697,696	$ 1,747,103	$ 1,804,882	$ -	$ -	$ -	$ -	$ 12,506,730
5	Total Transmission Revenues			$ 20,799,441	$ 18,397,523	$ 16,225,939	$ 16,704,825	$ 17,932,945	$ 25,702,666	$ 32,285,663	$ 32,754,637	$ -	$ -	$ -	$ -	$ 180,803,639

7/ 2015 Calendar Year Transmission Formula Rate (NITS & Ancillary Services)

2015 Calendar Year Transmission Formula Rate Retail Revenue Requirement ($252,204,617) plus Ancillary Services. $269,945,094

Over/(Under) Recovery $ (89,141,455)

ARIZONA CORPORATION COMMISSION STAFF'S FIFTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN DOCKET NO. E-01345A-16-0036 AND DOCKET NO. E-01345A-16-0123 OCTOBER 4, 2016

Staff 5.7: **Transmission Cost Adjustor**. For each year from the implementation of the APS TCA through the present, identify and quantify all unreconciled differences. For each such difference explain clearly whether it is an over- or under-recovered balance.

Response: Following are the actual transmission costs collected through base rates and the TCA as compared to the allowed recovery calculated in the Company's filed annual FERC transmission formula rate by year, in thousands, since inception. Please note that since we do not currently have a formal reconciliation process in place for the TCA, these amounts are approximations. Additionally, we are only requesting recovery of prospective over- or under-recovered amounts through the TCA and not historical amounts.

(in thousands)

Calendar Year	Actual Billed	Allowed Recovery	Over/(Under) Recovery
2008	$ 165,762	$ 168,171	$ (2,409)
2009	179,334	188,655	(9,321)
2010	186,847	178,716	8,131
2011	209,431	216,958	(7,527)
2012	228,783	235,366	(6,583)
2013	248,567	256,034	(7,467)
2014	252,856	260,158	(7,302)
2015	259,021	253,601	5,420
2016*	180,804	269,945	N/A

*The 2016 amounts presented reflect a full year of costs but only a partial year of revenue billed, thus the over/under recovery amount will be determined at year end when a full year of revenue is available.

Witness: Leland Snook

Arizona Public Service Company
Docket No. E-01345A-16-0036
Attachment RCS-17
Copies of Confidential APS' Responses to Data Requests and Workpapers Referenced in the Direct Testimony and Schedules of Ralph C. Smith

Confidential Pages have been Redacted

Data Request/ Workpaper No.	Subject	Confidential	No. of Pages	Page No.
Staff 5.8	Identification, descriptions, and costs for all environmental projects for years 2017 through 2020 for which the cost recovery would be requested through the EIS surcharge.	Yes	6	2 - 7
Staff 10.1	Projected cost information for the EIS, with and without the Four Corners' SCRs.	Yes	5	8 - 12
	Total Pages Including this Page		12	

ARIZONA CORPORATION COMMISSION STAFF'S
FIFTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-16-0036
AND
DOCKET NO. E-01345A-16-0123
OCTOBER 4, 2016

Staff 5.8: **Environmental Improvement Surcharge**.

a. Show in detail how the EIS has been calculated for 2015 and 2016.

b. Identify, describe and show the costs for all projects in 2017, 2018, 2019 and 2020 for which the cost recovery would be via the EIS surcharge.

Response:

a. For detail on the calculation of the EIS in the 2015 and 2016 filings, please refer to APS's attachments and response to Staff 5.56.

b. Please refer to Attachment APSRC01191 containing forecasted environmental projects in 2017, 2018, 2019 and 2020, in which recovery would be requested through the EIS surcharge. The attachment is confidential and is being provided pursuant to an executed confidentiality agreement.

Please note that the Selective Catalytic Reduction (SCR) direct construction costs of approximately $400 million for these federally mandated environmental projects are not included in the attachment. APS seeks a cost deferral order and step increase in rates to recover the SCR costs.

Witness: Leland Snook

PAGES 3-12 ARE CONFIDENTIAL AND HAVE BEEN REDACTED

**Arizona Public Service Company
Docket No. E-01345A-16-0036
Attachment RCS-18
Copies of Highly Confidential APS' Responses to Data Requests
and Workpapers Referenced in the Direct Testimony and Schedules of
Ralph C. Smith**

APS Highly Confidential Pages Have Been Redacted

Data Request/ Workpaper No.	Subject	Highly Confidential Information	No. of Pages	Page No.
Woodward 2.19	Cost of meter installation per unit.	Yes	4	2 - 5
	Total Pages Including this Page		5	

PAGES 2-5 ARE HIGHLY CONFIDENTIAL AND HAVE BEEN REDACTED